Appendix H
USEPA Air Quality Permit Application

AIR QUALITY PERMIT APPLICATION

GULF LANDING LNG REGASIFICATION TERMINAL

Submitted to:

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 Ross Avenue
Dallas, Texas 75202-2733

Submitted by:

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TABLE OF CONTENTS

LIST OF ACRONYMS

µg	microgram
API	American Petroleum Institute
BOG	boil off gas
BTU	British thermal unit
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
EPA	United States Environmental Protection Agency
ft	foot
GBS	gravity base structure
GEP	good engineering practice
GJ/hr	gigajoules per hour
HAP	hazardous air pollutant
HP	horsepower
hr	hour
LAC	Louisiana Administrative Code
LCAA	Louisiana Clean Air Act
LDEQ	Louisiana Department of Environmental Quality
LNG	liquefied natural gas
m	meter
MACT	maximum achievable control technology
MM	million
MMS	Minerals Management Service
NAAQS	national ambient air quality standards
NESHAP	national emission standards for hazardous air pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	new source performance standards
OCS	Outer Continental Shelf
OEA-EED	Office of Environmental Assessment, Environmental Evaluation Division
PM_{10}	particulate matter less than 10 microns

ppm	parts per million
PRV	pressure relief valve
PSD	prevention of significant deterioration
PTE	Potential to emit
SO_2	sulfur dioxide
SoLoNOx	Solar proprietary low nitrogen oxide emission technology
TAP	toxic air pollutant
TPY	tons per year
UHC	unburned hydrocarbon
VOC	volatile organic compound

1.0 INTRODUCTION

1.1 Background Information

Gulf Landing LLC (Gulf Landing) proposes to build a liquefied natural gas (LNG) receiving, storing, and regasification terminal approximately 38 miles offshore of Louisiana. The gravity base structure (GBS) regasification terminal will be composed of two concrete structures that will be built onshore, towed to site, and installed on the sea bed using proven construction methods and technology that have commonly and successfully been used in the offshore oil and gas industry for decades. To date, there are no GBS LNG regasification terminals in operation; however, concrete GBS structures are operating successfully worldwide for a variety of functions.

The structure proposed for Gulf Landing will consist of two caissons with a combined footprint approximately 1,110 feet (ft) long by 248 ft wide. The GBS will house two identical LNG storage tanks of 90,000 cubic-meters (m^3) net storage capacity each. An accommodation module is also provided for 60-person living quarters at the west end of the facility's western GBS.

1.2 Facility Location

The Gulf Landing LNG Terminal will be located in 55 ft of water in West Cameron Outer Continental Shelf (OCS) Block 213, approximately 38 miles offshore of Louisiana as shown in Figure 1-1.

1.3 Emission Sources

Table 1-1 lists the emission sources and annual emissions from the Gulf Landing LNG regasification terminal during normal operations. Mobile sources, such as tugboats and supply vessels not actually part of the Gulf Landing LNG regasification terminal, are not included in Table 1-1.

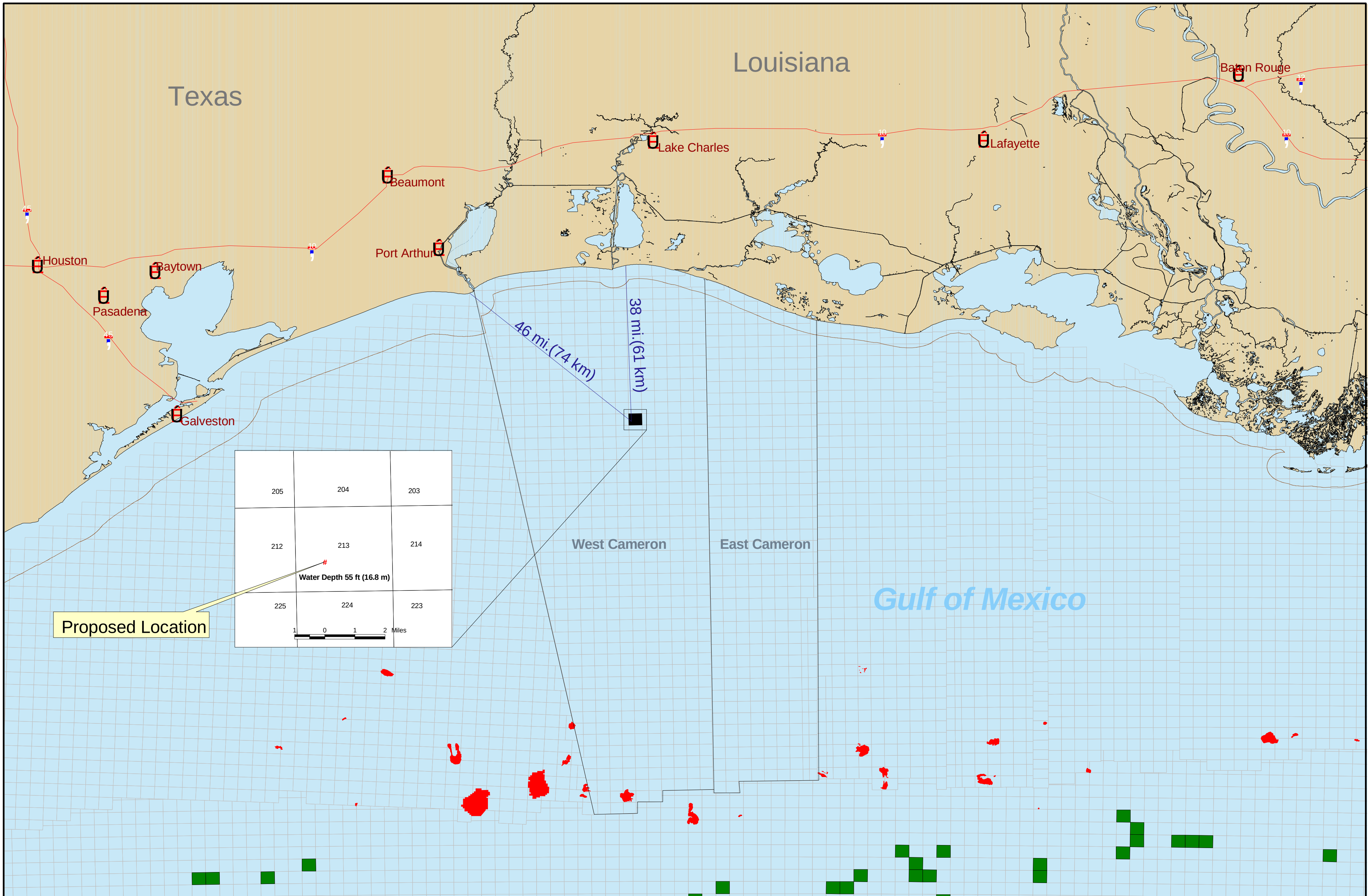
Sources to be permitted at the LNG terminal include the following:

- Solar Titan 130 gas turbine generator sets (3),
- Industrial cranes (3) – diesel-fired,
- Emergency firewater pumps (2) – diesel-fired,
- Emergency electrical generators (2) – diesel-fired,
- Sales gas heater,
- Diesel storage tank,
- Process flare, and
- Fugitive emissions.

As shown in Table 1-1, several of these sources will have air emissions less than 2 tons per year (TPY), and thus are termed "insignificant."

Table 1-1. Estimated Air Emissions Associated with Operation of Gulf Landing LNG Terminal

OPERATIONS	EQUIPMENT	RATING	MAX. FUEL	ACT. FUEL	RUN TIME		MAXIMUM POUNDS PER HOUR					ESTIMATED TONS				
	Diesel Engines	HP	GAL/HR	GAL/D												
	Natural Gas Engines	HP	SCF/HR	SCF/D												
	Burners	MMBTU/HR	SCF/HR	SCF/D	HR/D	DAYS	PM	SOx	NOx	VOC	CO	PM	SOx	NOx	VOC	CO
	Crane <600 HP Diesel	338	16.3254	391.81	1	52	0.74	1.09	10.42	0.83	2.26	0.02	0.03	0.27	0.02	0.06
	Crane <600 HP Diesel	338	16.3254	391.81	1	52	0.74	1.09	10.42	0.83	2.26	0.02	0.03	0.27	0.02	0.06
	Crane <600 HP Diesel	338	16.3254	391.81	1	52	0.74	1.09	10.42	0.83	2.26	0.02	0.03	0.27	0.02	0.06
	Emergency FW Driver 1100 HP	1100	53.13	1275.12	1	52	0.78	3.56	26.65	0.80	5.81	0.02	0.09	0.69	0.02	0.15
	Emergency FW Driver 1100 HP	1100	53.13	1275.12	1	52	0.78	3.56	26.65	0.80	5.81	0.02	0.09	0.69	0.02	0.15
	Solar Titan 130	16400	156193.6	3748646.40	24	365	6.78	0.55	14.50	0.50	17.65	29.70	2.40	63.50	2.20	77.30
	Solar Titan 130	16400	156193.6	3748646.40	24	365	6.78	0.55	14.50	0.50	17.65	29.70	2.40	63.50	2.20	77.30
	Solar Titan 130	16400	156193.6	3748646.40	24	8	6.78	0.55	14.50	0.50	17.65	0.65	0.05	1.39	0.05	1.69
PRODUCTION	Sales Gas Heater Natural Gas	20	19047.62	457142.86	24	365	0.14	0.01	1.90	0.10	1.60	0.63	0.05	8.34	0.46	7.01
	Emergency Generator 1100 HP	1100	53.13	1275.12	24	8	0.78	3.56	26.65	0.80	5.81	0.07	0.34	2.56	0.08	0.56
	Emergency Generator 1100 HP	1100	53.13	1275.12	24	8	0.78	3.56	26.65	0.80	5.81	0.07	0.34	2.56	0.08	0.56
	MISC	BPD	SCF/HR	COUNT												
	Tank	1			0	365				0.00					0.01	
	Flare		166,667		24	8		0.10	11.90	10.05	64.75		0.01	1.14	0.96	6.22
	Process Vent		0		0	0				0.00					0.00	
	Fugitives			20,000		365				10.00					43.80	
	Glycol Still Vent		0		0	0				0.00					0.00	
						TOTAL	**25.82**	**19.26**	**195.17**	**27.36**	**149.32**	**60.93**	**5.86**	**145.19**	**49.94**	**171.11**



LEGEND

West Cameron (WC) Block 213
City
State - Federal Boundary
MMS Lease Block
Interstate Highway
Known Chemosynthetic Block
Known Topographic Feature

N
W E
S
Scale
20 0 20 40 Miles

ecology and environment
International Specialist in the Environment
Baton Rouge, Louisiana

Figure 1-1

Proposed Location and Vicinity Map

Gulf Landing LNG Terminal

West Cameron Block 213

Solar Titan 130 Gas Turbine Generators

Three gas turbine generators will be used to provide electrical power to the terminal. Emissions are based on an operational rating of 16,400 horsepower (HP) each. Two of the turbines will be operating continuously, while the third will only be used for standby. Emissions for the standby unit are based on 192 hours of operation per year.

The turbines will be the largest source of air emissions at the terminal. However, they will utilize the low-nitrogen oxide (NO_X) solar technology referred to as SoLoNOx, which will substantially reduce emissions of both NO_X and carbon monoxide (CO) below those that might occur with a conventional gas combustion turbine.

Industrial Cranes

Three industrial cranes, rated at 338 HP each, will be used only occasionally through the year. The cranes will be diesel-fired, and are each estimated to be used only 52 hours per year.

Emergency Firewater Pumps

Similar to the cranes, two diesel-fired firewater pumps are each estimated to be used only 52 hours per year. The pumps are rated at 1,100 HP each.

Emergency Electrical Generators

Two diesel-powered electrical generators rated at 1,100 HP are each estimated to be used 192 hours per year.

Sales Gas Heater

In order to keep the sales gas heated (to avoid hydrate formation), a natural gas-fired burner will be used. The burner is rated at 20 million British thermal units per hour (MMBtu/hr) and will be operated continuously.

Diesel Storage Tank

One storage tank will be used for storage of the diesel fuel required for emergency equipment. The estimated usage rate is one barrel per day.

Process Flare

Under normal operating conditions, the facility will have no flaring or venting, and any boil off gases will be recondensed to LNG liquid and routed to the HP LNG pumps. For emergency conditions, there will be three emergency relief headers, a flare header, a low-pressure emergency vent header, and a HP emergency vent header. A self-igniting flare will be provided to safely dispose of emergency process releases. The flare is estimated to be used 192 hours per year at a maximum rate of 166,667 ft^3/hr.

Fugitive Emissions

Fugitive emissions will result of leaks from the many process valves, flanges, pump and compressor seals, and other fittings. The total number of components estimated at the terminal is 20,000.

The emissions were estimated based on an overall fugitive emission factor of 0.0005 lb/hr/component, as cited in the 1993 American Petroleum Institute (API) study. This is the default methodology used in the MMS Form 139 spreadsheet; however, it overestimates VOC emissions since in reality different components (valves, flanges, etc.) may leak at different rates. Also, most of the fugitive emissions are methane, which is not a VOC.

2.0 EMISSION CALCULATIONS

2.1 Emission Factors

Emissions calculations were performed using default factors provided by the Minerals Management Service (MMS) Form 139, with the exception that vendor-supplied estimates were used for the solar gas turbines (Appendix C – Vendor Specifications).

Most default emission factors are based on the United States Environmental Protection Agency's (EPA's) AP-42, Compilation of Air Pollution Emission Factors. However, emissions for miscellaneous sources such as the tank, flare, and fugitives were based on industry studies, as noted in the MMS Form 139.

The bases for fuel consumption values are the following:

- Diesel fuel energy content – 145,000 Btu/gallon
- Diesel engine efficiency factor – 7,000 Btu/HP-hr
- Natural gas fuel energy content – 1,050 Btu/scf
- Natural gas turbine efficiency factor – 10,000 Btu/HP-hr

For estimates of sulfur dioxide (SO_2) emissions, diesel fuel is assumed to contain 0.4% sulfur and natural gas has a sulfur content of 3.33 parts per million (ppm). (These are all the default MMS Form 139 factors.)

2.2 Operating Scenario

For purposes of determining the facility potential to emit (PTE), not all equipment is assumed to be operating continuously. Operational limitations are requested on Section G of Form GIS (Appendix A) to make these limitations federally enforceable.

Although a total of three gas combustion turbines are being permitted, it is important to note that only two will be operating concurrently, with the exception of a startup/shutdown or other non-routine operation. Thus, the PTE for the group of three turbines is represented as two turbines operating continuously (8760 hours per year, each), and the third (standby) turbine based on 192 hours of operation per year.

This is not to imply that the third turbine cannot be operated more than 192 hours per year; rather, the group of three turbines may be allowed to operate in any necessary combination for a total annual run time of 17,712 hours. This is necessary to allow for swapping individual turbines in and out of service throughout the year for maintenance purposes. (In other words, no single turbine is being designated as "the" standby unit. Each turbine will be rotated into the standby position throughout the year.)

Operational limitations are also requested for the diesel-powered equipment. The cranes and emergency firewater pumps will be limited to 52 hours of use per year, and the emergency generators will be limited to 192 hours per year.

2.3 Startup/Shutdown Emissions

Gulf Landing will balance the utilization of the turbine generator engines. Any two of the three turbines will operate at one time, with the third turbine acting only as standby or undergoing maintenance activities. Turbine rotation is estimated to occur about every 500 hours of turbine utilization (35 events per year for the two turbines). According to the manufacturer of the solar turbines, startup/shutdown is expected to take only about 10 minutes, which would minimize excess emissions.

Vendor data (Appendix C) indicates maximum NO_X, CO, and unburned hydrocarbons (UHC) emissions for a Solar Titan 130 turbine to be about 1.5, 37.3, and 3.0 pounds during the short start-up sequence, respectively. Likewise, shutdown emissions for NO_X, CO, and UHC are estimated at 1.9, 29.8, and 2.4 pounds, respectively.

The total emissions for a complete startup/shutdown cycle is then estimated to be 3.4, 67.1, and 5.4 pounds for NO_X, CO, and UHC, respectively. Assuming 35 startup/shutdown events per year yields startup/shutdown emissions as shown in Table 2-1. Estimated yearly emissions from startup/shutdown operations are expected to be insignificant.

Table 2-1. Estimated Startup/Shutdown Emissions for Gas Turbines

Pollutant	Each Startup/Shutdown Cycle		Estimated Annual Emissions	
	lbs	tons	lbs	tons
NO_X	3.4	0.0017	119	0.06
CO	67.1	0.0336	2349	1.17
UHC[a]	5.4	0.0027	189	0.09

[a] Total UHC is an overestimation of volatile organic compound (VOC) emissions since not all hydrocarbons are defined as VOCs.

2.4 Hazardous Air Pollutants (HAPs)

Emissions of hazardous air pollutants (HAPs) were calculated for the diesel-powered cranes utilizing emission factors from AP-42 Table 3.3-2 "Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines." HAPS were calculated for the diesel generators and firewater pumps utilizing the AP-42 Table 3.4-3 and Table 3.4-4 "Emission Factors for Large Uncontrolled Stationary Diesel Engines."

HAPs from the Solar Titan 130 gas turbines were estimated based on AP-42 Table 3.1-3 "Emission Factors for HAPs from Natural Gas-Fired Stationary Gas Turbines," with the exception of formaldehyde. Formaldehyde was estimated based on the recommended factor from the Louisiana Department of Environmental Quality (LDEQ). This results in a conservatively high estimate for both formaldehyde and total HAPs. A summary of the HAPs from the proposed Gulf Landing LNG Terminal is shown, along with supporting calculations, in Appendix B.

Total HAP emissions from the terminal will be about 6.5 TPY, with the majority of HAPs attributed to formaldehyde (5.1 TPY). Neither amount exceeds the HAPs threshold for applying controls of 10 TPY of any single HAP, and 25 TPY of a combination of HAPs. HAPs are reported as part of the Title V application under Section J of Form GIS (Appendix A).

2.5 Air Emissions Summary

Estimated emissions of regulated pollutants were previously presented in Table 1-1. They are also on Form PTE of the Title V permit application forms, located in Appendix A. Emission calculation worksheets for hazardous air pollutants are located in Appendix B.

3.0 REGULATORY APPLICABILITY

3.1 New Source Performance Standards (NSPS)

The owner or operator of any stationary source that contains an affected facility that is constructed, reconstructed, or modified after the effective date of an applicable new source performance standard (NSPS) is subject to that NSPS. NSPS requirements are promulgated under 40 Code of Federal Regulations (CFR) Part 60, pursuant to Section 111 of the Clean Air Act (CAA). Each NSPS contains emission standards for the affected pollutants, defines compliance provisions such as the requirements for source testing and continuous emission monitors, and specifies the recordkeeping and reporting requirements.

40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines

The NSPS Subpart GG, "Standards of Performance for Stationary Gas Turbines," (40 CFR Part 60, Subpart GG, as amended by EPA Final Rule April 14, 2003, published in the Federal Register at 68 FR 17990) are implemented by the EPA and are applicable to stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (GJ/hr). NO_X and sulfur dioxide (SO_2) emission restrictions apply.

This regulation applies to stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr. The Gulf Landing LNG Terminal will utilize gas turbines meeting the applicability criteria, thus this regulation applies to the three turbines. In summary, all three turbines must:

- Comply with NO_X standards as specified in 40 CFR Part 60.332(a)(1).
- Compute the NO_X emissions rate utilizing the equation specified in 40 CFR Part 60.335(c)(1);
- Conduct initial testing of NO_X and O_2 and any subsequent testing under the requirements of 40 CFR Part 60.335(c)(3); and
- Maintain SO_2 emissions <0.015 % by volume at 15% oxygen on dry basis, or only burn fuel with sulfur <0.8% by weight (40 CFR Part 60.333(a) and (b)).

During liquefaction of LNG the sulfur is removed. Consequently, SO_2 emissions in the regasified natural gas will be negligible. Utilizing natural gas in the turbines ensures compliance with the sulfur limit of the standard.

Form I-COMP presents Gulf Landing's plan for maintaining compliance with Subpart GG. This form is included in Appendix A.

3.2 National Ambient Air Quality Standards (NAAQS)

Federal and state regulations protect ambient air quality. The EPA has developed primary and secondary national ambient air quality standards (NAAQS) for six criteria air pollutants including: ozone, nitrogen dioxide (NO_2), CO, SO_2, and particulate matter less than 10 microns (PM_{10}). Additionally, a new particle size of 2.5 micrometers (µm) or less ($PM_{2.5}$) was recently promulgated by EPA, along with a new 8-hour ozone standard. Areas of the country that are currently in violation of NAAQS are classified as nonattainment areas, and new sources to be located in or near these areas could be subject to more stringent air permitting requirements.

Diesel fuel combustion sources emit these criteria air pollutants, along with VOCs, a precursor of ozone. However, the gas used to fuel the turbines will be comprised mostly of methane, and VOCs will be very low, as shown on Table 1-1.

The state of Louisiana is in attainment for all criteria pollutants, except the 1-hour ozone NAAQS, which is exceeded in five parishes (East Baton Rouge, West Baton Rouge, Livingston, Ascension and Iberville). These five nonattainment parishes surround the city of Baton Rouge, located approximately 160 miles from the proposed terminal. Therefore, emissions from the terminal are not expected to impact any onshore nonattainment areas.

The criteria pollutants and their air quality impact from the terminal are discussed in more detail below.

Ozone

Ozone is a photochemical oxidant and the major component of smog. Ozone is generated by a complex series of chemical reactions between VOCs and NO_X in the presence of ultraviolet radiation. High ozone levels result from VOCs and NO_X emissions from vehicles and industrial sources, in combination with daytime wind flow patterns, mountain barriers, a persistent temperature inversion, and intense sunlight. For this reason, VOC and NO_X are considered precursors to ozone and are consequently regulated as ozone. The terminal would emit VOCs and NO_X from three turbine generators, diesel-powered equipment, and fugitives. However, these emissions, along with other minor sources associated with the terminal, are not expected to adversely affect the onshore air quality because of the 38-mile distance to shore.

Nitrogen Dioxide (NO_2)

NO_2 emissions are primarily generated from the combustion of fuels. Nitrogen oxides include nitric oxide and NO_2. Because nitric oxide converts to NO_2 in the atmosphere over time and NO_2 is the more toxic of the two, NO_2 is the listed criteria pollutant. The control of NO_X is also important because of its role in the formation of ozone, as stated above. Potential NO_X emissions from the terminal's natural gas and diesel combustion sources will total about 145 TPY.

Volatile Organic Compound (VOC)

VOCs are primarily generated at this site as unburned hydrocarbons from the turbines and engines, as well as fugitive emissions. As stated above, VOC is an ozone precursor. Potential VOC emissions from the terminal will total about 50 TPY.

Carbon Monoxide (CO)

CO is a product of inefficient combustion. The terminal's natural gas-powered turbines will have a potential to emit approximately 156 TPY of CO. Total potential CO emissions from the terminal are estimated at about 171 TPY.

Sulfur Dioxide (SO_2)

SO_2 is produced when any sulfur-containing fuel is burned. The regasified LNG from the terminal will not contain sulfur, as the sulfur is removed during the liquefaction process. The turbines will therefore not emit SO_2, but are calculated at the 3.33 ppm level to account for worst case conditions. Potential emissions of SO_2 from the terminal will total about 6 TPY.

Particulate Matter

Particulates in the air are caused by a combination of wind-blown fugitive dust, particles emitted from combustion sources (usually carbon particles); and organic, sulfate, and nitrate aerosols formed in the air from emitted hydrocarbons, sulfur oxides, and NO_X. The diesel-powered equipment will be a source of PM_{10}, but will be operated as emergency equipment only. Total potential PM_{10} for the terminal is estimated to be about 61 TPY.

Lead

Lead will not be emitted from any of the project sources.

3.3 Prevention of Significant Deterioration (PSD)

The regulations under the Federal Prevention of Significant Deterioration (PSD) program, administered by the EPA, are intended to preserve the existing air quality in areas where pollutant levels are below the NAAQS. PSD regulations impose specific limits on the amount of pollutants that major new or modified stationary sources may contribute to existing air quality levels.

Major sources are defined as facilities with a potential to emit criteria pollutants in amounts equal to or greater than 250 TPY, or 100 TPY for 28 specific source categories. The Gulf Landing LNG Terminal will not be subject to PSD pre-construction review because it will not exceed the 250-ton threshold nor is it one of the 28 listed source categories for which the 100-ton limit applies. However, the 250-ton threshold will not be exceeded only due to a restriction of operating hours on process equipment such as emergency generators and the standby gas turbine.

This restriction of operating hours will be an enforceable limit in the permit. This type of permit makes the facility a “synthetic minor” because if the entire PTE were included for all sources (i.e., all sources operating continuously) then the 250-ton threshold would be exceeded for one or more pollutants.

3.4 Federal New Source Review NSR Requirements

In order to prevent new sources of emissions from deteriorating existing air quality beyond acceptable levels, a federal review process was established. There are separate procedures for federal pre-construction review of certain large proposed projects in attainment areas versus nonattainment areas. The Nonattainment New Source Review is a federal pre-construction review for affected sources in nonattainment areas. Because the proposed terminal will not be located within the boundaries of a nonattainment area, the project would not be subject to Nonattainment New Source Review Permitting. Instead, the terminal will be permitted as a “synthetic minor” facility.

3.5 National Emission Standards for Hazardous Air Pollutants (NESHAP)

National Emission Standards for Hazardous Air Pollutants (NESHAP) Parts 61 and 63 regulate the emission of hazardous air pollutants from existing and new sources. However, the proposed project is not expected to operate any processes that are regulated by Part 61.

Part 63 provides standards for major sources of hazardous air pollutants (HAPs). The Clean Air Act Amendments of 1990, under revisions to Section 112, required the EPA to list and promulgate NESHAPS to reduce the emissions of HAPs, (such as formaldehyde, benzene, xylene, and toluene) from categories of major and area sources. As these standards are promulgated, they are published in Title 40, CFR, Part 63.

Stationary gas turbines are listed among the source categories that would be subject to emission standards. Standards for stationary gas turbines that were scheduled for promulgation by November 15, 2000 have missed the regulated deadline. Stationary gas turbines are now subject to the "MACT hammer" which means they are applicable to Maximum Achievable Control Technology (MACT) standards on a case-by-case basis as determined by the regulating agency.

The proposed project would not be subject to the standards unless it becomes a major source of HAPs, which is a facility-wide potential emissions threshold of 10 TPY or greater of any one HAP, or a combination of HAPs of 25 TPY or greater. However, as previously shown in Section 2.4 and HAP calculations located in Appendix B, the terminal will not be a major source of HAPS; therefore, Section 112 MACT standards do not apply. Potential HAP emissions from the turbines will not exceed 6 TPY.

The EPA recently promulgated NESHAPs for natural gas transmission and storage facilities (40 CFR 63 Subpart HHH). Owners and operators of facilities that only transport natural gas are not subject to this regulation if their facility does not contain a glycol dehydration unit. The proposed terminal is not a major HAP source, nor will it operate a glycol dehydration unit. Therefore, Subpart HHH would not apply.

3.6 Title V Operating Permits

Federal Title V of the CAA Amendments of 1990, as outlined in 40 CFR Part 71 (Part Operating Permit), requires a Federal Operating Permit for major sources of criteria pollutants as administered by the EPA. Part 70 Title V Permits are managed within state or local jurisdiction. Designation of a major source is contingent on the attainment status of the air basin. Since the proposed project is located in OCS waters and is subject to federal air quality permitting, it would fall under the jurisdiction of Part 71 as a major Title V source (having the PTE over 100 TPY of a criteria pollutant). The project will require a Title V Operating Permit under the jurisdiction of EPA Region 6, for which this application is submitted. (See Appendix A for permit application forms.)

3.7 Compliance Assurance Monitoring

The Federal Title V Operating Permit will list all federally enforceable air regulations and a compliance plan for meeting each regulatory requirement. In accordance with EPA, as published at 40 CFR Part 64, a Compliance Assurance Monitoring (CAM) Plan must be prepared for each piece of equipment proposed for operation at a new or modified facility. EPA requires CAM plans for all new major sources, as well as for existing sources at the required five-year renewal application.

In order to demonstrate compliance with emission limitations, emission monitoring shall meet general criteria where the monitoring shall be designed to obtain data for appropriate indicators of emission control equipment performance. These indicators can include direct or predicted emissions, process and control device parameters affecting control efficiency, or records of inspection and maintenance activities. Appropriate ranges or conditions for the selected indicators shall be established so that equipment operation within the range or under the conditions demonstrates compliance with emission limitations. In addition, indicator ranges or conditions shall be designed as follows: 1) based on a single value; 2) expressed as a function of process variables; 3) expressed as maintaining the applicable parameter in a particular operational status; or 4) established as interdependent between more than one indicator.

Emission monitoring shall also meet performance criteria where data must be representative of the emissions or parameters being monitored, and for new equipment, verification procedures confirming operational status of the monitoring prior to the date by which monitoring is required. Adequate quality assurance and control practices must also be in place to ensure the continued validity of the data.

Documentation that satisfies the monitoring design criteria must be submitted to the appropriate permitting authority. The documentation must contain the following: 1) indicators to be monitored and their ranges or conditions; and 2) performance criteria, and if applicable, the performance criteria for any continuous emissions monitoring systems.

The Gulf Landing LNG Terminal will comply with CAM for the turbine generators, which will have NO_X and SO_2 emission limits under NSPS Subpart GG. The project will comply with CAM for all diesel-powered equipment and for the emergency flare, as demonstrated by the Initial Compliance Plan and Compliance Certification forms (Form I-COMP) for the major source equipment (shown in Appendix A).

3.8 State Air Quality Regulations

Although the Gulf Landing LNG Terminal is located outside the state jurisdictional boundary for Louisiana, EPA has determined that the facility is subject to Louisiana regulations pertaining to individual pollutants and sources, beyond the federal requirements. LDEQ's air quality regulations are codified in Louisiana Administrative Code (LAC) Title 33, Part III. Pursuant LAC 33:III.502, any facility that directly emits or has the PTE 100 TPY of any regulated air pollutant excluding HAP's is defined as a major source. Therefore, under Louisiana regulations, the facility would be considered major. General application requirements are included in LAC 33:III.517. These requirements include citing and detailing compliance with all Louisiana and federal air quality requirements and standards and a review of proposed emission controls.

The remainder of this section provides the information necessary to show the Gulf Landing LNG terminal will comply with the requirements in LAC 33:III. The emissions and plant operations from the proposed new facility will comply with all rules and regulations of LDEQ and with the intent of the Louisiana Clean Air Act (LCAA), including the protection of the health and physical property of the people. A summary discussion on compliance with each applicable rule is included below.

Chapter 9 – General Regulations on the Control of Emissions and Emission Standards

Chapter 9 includes the general rules that are applicable to all sources. Gulf Landing will comply with the applicable requirements of this chapter. The applicable sections within this chapter are:

- §913 – New Sources to Provide Sampling Ports.

- §915 – Emission Monitoring Requirements
  Since facility is subject to a federal new source performance standard, 40 CFR 60 Subpart GG, pursuant to LAC 33:III.915D, no additional monitoring requirements apply.

- §918 – Recordkeeping and Annual Reporting
  Emission reports for the preceding calendar year are required to be submitted to LDEQ Office of Environmental Assessment, Environmental Evaluation Division (OEA-EED) by March 31st of each year.

- §919 – Emission Inventory
  Facilities that are classified as major are required to submit an annual emissions inventory to LDEQ on magnetic media in a format specified by OEA-EED. Minimum Data Requirements and Calculation methodology are specified in LAC 33:III.919.B.5 and 919.C.

- §921 – Stack Heights
  The facility will not get credit for any control associated with utilizing a stack which exceed good engineering practice (GEP) stack height as defined in LAC 33:III.921.A.

- §927 - Notification Required (Unauthorized Discharges)
  Gulf Landing will submit written reports of the unauthorized discharge of any air pollutant in accordance with LAC 33:I.Chapter 39, Notification Regulations and Procedures for Unauthorized Discharges.

- §929 – Violation of Emission Regulations Cannot be Authorized
  Gulf Landing will not cause or contribute to the violation of any NAAQS or emission standard included in LAC 33.III.

Chapter 11 – Control of Emissions of Smoke

The applicable sections within this chapter are:

- §1101 – Control of Air Pollution from Smoke
  Emissions of smoke from any combustion unit or any type of burning in a combustion unit (other than a flare) shall not exceed 20% opacity at any time, except in startup mode at which time one excess emission of 20% is allowed for one 6-minute period in any 60 consecutive minutes.

- §1105 – Smoke from Flaring shall not exceed 20% Opacity
  Flares used to control process upsets must be controlled to limit exceedences of 20% opacity to less than 6 hours in any 10 consecutive days.

Chapter 13 – Emission Standards for Particulate Matter (Including Standards for Some Specific Facilities)

Subchapter A – Emission Standards for Particulate Matter

- §1303 – Provisions Governing Specific Activities
  The Gulf Landing LNG Terminal will not emit toxic substances that need additional control, nor will it impair visibility in the area such as to affect ship traffic.

- §1305 – Control of Fugitive Emissions
  No fugitive particulate emissions are expected to be generated by activities associated with the construction or operation of this facility.

- §1307 – Degradation of Existing Quality Restricted
  Particulate matter emitted from the processes at the Gulf Landing LNG terminal will be maintained at the prescribed levels guaranteed by the equipment manufacturer and will be lower than the regulatory limits established in this regulation.

- §1309 – Measurement of Concentration
  Gulf Landing LNG will measure particulate concentrations in the stack gases in accordance with LDEQ approved methods and standards.

Subchapter C – Fuel Burning Equipment

- §1313 – Emissions from Fuel Burning Equipment
  Particulate emissions generated by fuel burning equipment are limited to 0.6 pounds per million BTU of heat input.

Chapter 15 – Emission Standards for Sulfur Dioxide

- §1501 – Degradation of Existing Emission Quality Restricted
  SO_2 emitted from the processes at the Gulf Landing LNG terminal will be maintained at the prescribed levels guaranteed by the equipment manufacturer and will be lower than the regulatory limits established in this regulation.

- §1503 – Emission Limitations
  SO_2 emitted by this facility will not exceed 2,000 ppm by volume for any three consecutive hour period. SO_2 concentrations in the stack gases will be measured in accordance with LDEQ approved methods and standards.

- §1511 – Continuous Emission Monitoring
  Since SO_2 emissions generated by this facility will not exceed 100 TPY, continuous emission monitoring is not required.

- §1513 – Recordkeeping and Reporting
  Gulf Landing LNG will record and retain data at the site for at least two years to show compliance with these regulatory requirements and permit limitations.

Chapter 17 – Control of Emissions of CO (New Sources)

- §1701 – Degradation of Existing Emission Quality Restricted
  CO emitted from the processes at the Gulf Landing LNG terminal will be maintained at the prescribed levels guaranteed by the equipment manufacturer and will be lower than the regulatory limits established in this regulation.

Chapter 21 – Control of Emissions of Organic Compounds

Subchapter A – General

- §2103 – Storage of VOCs
  The Gulf Landing LNG Terminal is designed with storage vessels which will maintain working pressures sufficient at all times under normal operating conditions to prevent vapor or gas loss to the atmosphere. The tanks will have submerged pumps and all vapors are captured and controlled through the boil off gas (BOG) compression system or are flared in upset conditions.

- §2121 – Fugitive Emission Control
  This facility will maintain and monitor its LNG vaporization units and other equipment to minimize equipment leaks in accordance with the provisions of this requirement. Vapors from pressure relief valves (PRV's) are routed back to the storage tanks or to a flare providing control for these systems.

Chapter 22 – Control of Emissions of NO_X

- §2201 – Affected Facilities in the Baton Rouge Nonattainment Area and the Region of Influence
  The Gulf Landing LNG Terminal is not located in the Baton Rouge Nonattainment Area or the Region of Influence; therefore these rules are not applicable to this facility.

Chapter 29 – Odor Regulations

- §2901 – Odorous Substances
  The Gulf Landing LNG terminal will not emit odorous substances and therefore will comply with the provisions of this rule.

Chapter 51 – Comprehensive Toxic Air Pollutant Emission Control Program

Subchapter A – Applicability, Definitions and General Provisions

- §5101 – Applicability
  The facility will not generate 10 TPY of any toxic air pollutant (TAP) in tables 51.1, 51.2 or 51.3 or 25 TPY of a combination of TAPs, therefore the facility will not be a major source and the provisions of this chapter do not apply.

APPENDIX A - TITLE V (PART 71) PERMIT APPLICATION FORMS

PERMIT APPLICATION FORMS

40 CFR PART 71
FEDERAL OPERATING PERMITS PROGRAM

US EPA
JANUARY, 2001

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM GIS - GENERAL INFORMATION AND SUMMARY

Instructions: Complete this form once for the part 71 source (facility).

A. Mailing Address and Contact Information

Facility name **Gulf Landing**

Mailing address: Street or P.O. Box **1301 McKinney Suite 700**

City **Houston** State **TX** ZIP **77010** -

Contact person: **Larry Jensen** Title **Director, Regulatory Affairs**

Telephone (**713**) **230** - **3134** Ext. Facsimile (**713**) **265** - **3134**

B. Facility Location

Temporary source? ___ Yes **X** No Plant site location **US Gulf of Mexico, West Cameron Block 213**

City **Offshore** State **LA** County **N/A** EPA Region **6**

Is the facility located within:

Indian lands? ___YES **X** NO OCS waters? **X** YES ___ NO

Nonattainment area? ___ YES **X** NO If yes, for what air pollutants? **N/A**

Within 50 miles of affected State? **X** YES ___ NO If yes, What State(s)? **LA**

C. Owner

Name **Gulf Landing LLC** Street/ P.O. Box **1301 McKinney, Suite 700**

City **Houston** State **TX** ZIP **77010** -

Telephone (**713**) **230** - **3708** Ext.

D. Operator

Name **Gulf Landing LLC** Street/ P.O. Box **1301 McKinney, Suite 700**

City **Houston** State **TX** ZIP **77010** -

Telephone (**713**) **230** - **3134** Ext.

E. Application Type

Instructions: Mark only one permit application type and answer the supplementary question appropriate for the type marked.

_X__ Initial Permit ___ Permit Renewal ___ Significant Mod. ___ Minor Permit Mod. (MPM)

___ Group Processing, MPM ___ Administrative Amend.

For initial permits, when did operations commence? ____**01/2009**____

For permit renewals, what is the expiration date of the existing permit? _____ /_____ /_____

F. Applicable Requirement Summary

Instructions: Mark all applicable requirements that apply.

___ SIP ___ FIP/TIP ___ PSD ___ Nonattainment NSR

___ Minor source NSR _X__ Section 111 ___ Phase I acid rain ___ Phase II acid rain

___ Stratospheric ozone _X OCS regulations ___ NESHAP ___ Sec. 112(d) MACT

___ Sec. 112(g) MACT ____Early reduction of HAP ___ Sec. 112(j) MACT ___ RMP [Sec.112(r)]

___ Tank vessel reqt., section 183(f) ___ Section 129 Standards/Reqts.

___ Consumer/ commercial prod. reqts., section 183(e) ___ NAAQS, increments or visibility (for temporary sources)

Has a risk management plan been registered? ___ YES _X__ NO Regulatory agency ___________________________

Has a phase II acid rain application been submitted? ___ YES _X_ NO Permitting authority_______________________

G. Source-Wide PTE Restrictions and Generic Applicable Rquirements

Instructions: Cite and describe (1) any emissions-limiting requirements that apply to the facility as a whole, and (2) "generic" applicable requirements that apply broadly or in an identical fashion to all sources at the facility.

1) Two of the three turbines will each operate a potential of 8760 hrs/yr. The third turbine will be used for backup and will operate a potential of 192 hrs/yr. To maintain even maintenance and wear on the three turbines, each turbine will be used for both full time and backup operation.
2) Diesel crane engines will each operate at a maximum of 52 hrs/yr during normal operations.
3) Diesel firewater pumps will each operate at a maximum of 52 hrs/yr during normal operations..
4) Emergency generators will each operate at a maximum of 192 hrs/yr during normal operations.

I. Process Description

Instructions: List all processes, products, and SIC codes for normal operation, in order of priority. Also list any process, products, and SIC codes associated with any alternative operating scenarios, if different from those listed for normal operation

Process	Products	SIC
Marine Cargo Handling Facility	**LNG & Regasification Natural Gas**	**4491**

Form **GIS** Continued

I. Emission Unit Identification

Instructions: Assign an emissions unit ID and describe each significant emissions unit at the facility. Control equipment and/or alternative operating scenarios associated with emissions units should by listed on a separate line. Applicants may exclude from this list any insignificant emissions units or activities.

Emissions Unit ID	Description of Unit
TURB01	**Solar Titan Low NOx Turbine**
TURB02	**Solar Titan Low NOx Turbine**
TURB03	**Solar Titan Low NOx Turbine**
HEAT01	**Sales Gas Heater, LNG vap.**
EGEN01	**Emergency Generator, LNG vap**
EGEN02	**Emergency Generator, LNG vap**
FLAR01	**Emergency Flare**
FUG01	**Fugitive Emissions**

J. Facility Emissions Summary

Instructions: Enter potential to emit (PTE) for the facility as a whole for each air pollutant listed below. Enter the name of the single HAP emitted in the greatest amount and its PTE. For all pollutants stipulations to major source status may be indicated by entering "major" in the space for PTE. Indicate the total actual emissions for fee purposes for the facility in the space provided. Applications for permit modifications need not include actual emissions information

NOx **145.2** tons/yr VOC **49.9** tons/yr SO2 **5.9** tons/yr

PM-10 **60.9** tons/yr CO **171.1** tons/yr Lead **0** tons/yr

Total HAP **6.5** tons/yr

Which single HAP emitted in the greatest amount? **Formaldehyde** PTE **5.10** tons/yr

Total emissions of regulated pollutants (for fee calculation) from section F, line 5 of form **FEE?** **0** tons/yr

K. Existing Federally Enforceable Permits:

Permit number(s) **N/A** Permit type **N/A** Permitting authority **N/A**

Permit number(s) **N/A** Permit type **N/A** Permitting authority **N/A**

L. Emission Unit(s) Covered by General Permits

Emission unit(s) subject to general permit **N/A** ______

Check one: ___ Application made ___ Coverage granted

General permit identifier ______ Expiration Date ____/____/____

M. Cross-referenced Information

Does this application cross-reference information? ___ YES **X** NO (If yes, see instructions)

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM IE - INSIGNIFICANT EMISSIONS

INSTRUCTIONS: List each source eligible for insignificant treatment under § 71.5(c)(11)(ii). In the "number" column, indicate the number of units qualifying under each description. Each description must be specific enough to describe the source of emissions. List emission units separately if they have dissimilar descriptions, including dissimilar capacities or sizes and other factors. Please check the appropriate column to indicate whether the source meets the emissions criteria under § 71.5(c)(11)(ii)(A) and (B) for regulated air pollutants except hazardous air pollutant (RAP, except HAP), and for HAP, respectively.

Number	Description of Activities or Emission Units	RAP, except HAP	HAP
3	**Crane < 600 hp diesel**	**X**	**X**
2	**Emergency Fire Water Driver – 1100 hp**	**X**	**X**
1	**Diesel Tank**	**X**	

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM EMISS - EMISSIONS CALCULATIONS

INSTRUCTIONS: Use this form to calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _**TURB01**___________

B. Identification and Quantification of Emissions

Instructions: First, list each air pollutant that is either regulated at the unit or present in major amounts. Second, list any other regulated pollutant (for fee calculation) emitted at the unit that have not already been listed. Each HAP added to the list in this step may be simply listed as "HAP". Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each listed air pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives, including those that do not count towards applicability, when calculating actual emissions. At a minimum, round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values. Attach examples of calculations that illustrates the methodology used.

Air Pollutants (including regulated air pollutants and pollutants for which the source is major)	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx	**0**	**14.5**	**63.5**	
PM	**0**	**6.8**	**29.7**	
SOx	**0**	**0.6**	**2.4**	
VOC	**0**	**0.5**	**2.2**	
CO	**0**	**17.7**	**77.3**	
HAP - Formaldehyde	**0**	**0.6**	**2.5**	**50000**

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM EMISS - EMISSIONS CALCULATIONS

INSTRUCTIONS: Use this form to calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _**TURB02**___________

B. Identification and Quantification of Emissions

Instructions: First, list each air pollutant that is either regulated at the unit or present in major amounts. Second, list any other regulated pollutant (for fee calculation) emitted at the unit that have not already been listed. Each HAP added to the list in this step may be simply listed as "HAP". Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each listed air pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives, including those that do not count towards applicability, when calculating actual emissions. At a minimum, round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values. Attach examples of calculations that illustrates the methodology used.

Air Pollutants (including regulated air pollutants and pollutants for which the source is major)	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx	**0**	**14.5**	**63.5**	
PM	**0**	**6.8**	**29.7**	
SOx	**0**	**0.6**	**2.4**	
VOC	**0**	**0.5**	**2.2**	
CO	**0**	**17.7**	**77.3**	
HAP - Formaldehyde	**0**	**0.6**	**2.5**	**50000**

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM EMISS - EMISSIONS CALCULATIONS

INSTRUCTIONS: Use this form to calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _**TURB03**___________

B. Identification and Quantification of Emissions

Instructions: First, list each air pollutant that is either regulated at the unit or present in major amounts. Second, list any other regulated pollutant (for fee calculation) emitted at the unit that have not already been listed. Each HAP added to the list in this step may be simply listed as "HAP". Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each listed air pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives, including those that do not count towards applicability, when calculating actual emissions. At a minimum, round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values. Attach examples of calculations that illustrates the methodology used.

Air Pollutants (including regulated air pollutants and pollutants for which the source is major)	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx	**0**	**14.5**	**1.4**	
PM	**0**	**6.8**	**0.7**	
SOx	**0**	**0.6**	**0.1**	
VOC	**0**	**0.5**	**0.1**	
CO	**0**	**17.7**	**1.7**	
HAP - Formaldehyde	**0**	**0.6**	**0.1**	**50000**

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM EMISS - EMISSIONS CALCULATIONS

INSTRUCTIONS: Use this form to calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _**HEAT01**___________

B. Identification and Quantification of Emissions

Instructions: First, list each air pollutant that is either regulated at the unit or present in major amounts. Second, list any other regulated pollutant (for fee calculation) emitted at the unit that have not already been listed. Each HAP added to the list in this step may be simply listed as "HAP". Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each listed air pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives, including those that do not count towards applicability, when calculating actual emissions. At a minimum, round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values. Attach examples of calculations that illustrates the methodology used.

Air Pollutants (including regulated air pollutants and pollutants for which the source is major)	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx	**0**	**1.9**	**8.3**	
PM	**0**	**0.1**	**0.6**	
SOx	**0**	**0.01**	**0.1**	
VOC	**0**	**0.1**	**0.5**	
CO	**0**	**1.6**	**7.0**	

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM EMISS - EMISSIONS CALCULATIONS

INSTRUCTIONS: Use this form to calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _**EGEN01**____________

B. Identification and Quantification of Emissions

Instructions: First, list each air pollutant that is either regulated at the unit or present in major amounts. Second, list any other regulated pollutant (for fee calculation) emitted at the unit that have not already been listed. Each HAP added to the list in this step may be simply listed as "HAP". Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each listed air pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives, including those that do not count towards applicability, when calculating actual emissions. At a minimum, round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values. Attach examples of calculations that illustrates the methodology used.

Air Pollutants (including regulated air pollutants and pollutants for which the source is major)	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx	**0**	**26.7**	**2.6**	
PM	**0**	**0.8**	**0.1**	
SOx	**0**	**3.6**	**0.3**	
VOC	**0**	**0.8**	**0.1**	
CO	**0**	**5.8**	**0.6**	

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM EMISS - EMISSIONS CALCULATIONS

INSTRUCTIONS: Use this form to calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _**EGEN02**

B. Identification and Quantification of Emissions

Instructions: First, list each air pollutant that is either regulated at the unit or present in major amounts. Second, list any other regulated pollutant (for fee calculation) emitted at the unit that have not already been listed. Each HAP added to the list in this step may be simply listed as "HAP". Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each listed air pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives, including those that do not count towards applicability, when calculating actual emissions. At a minimum, round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values. Attach examples of calculations that illustrates the methodology used.

Air Pollutants (including regulated air pollutants and pollutants for which the source is major)	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx	**0**	**26.7**	**2.6**	
PM	**0**	**0.8**	**0.1**	
SOx	**0**	**3.6**	**0.3**	
VOC	**0**	**0.8**	**0.1**	
CO	**0**	**5.8**	**0.6**	

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM EMISS - EMISSIONS CALCULATIONS

INSTRUCTIONS: Use this form to calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _**FLAR01**

B. Identification and Quantification of Emissions

Instructions: First, list each air pollutant that is either regulated at the unit or present in major amounts. Second, list any other regulated pollutant (for fee calculation) emitted at the unit that have not already been listed. Each HAP added to the list in this step may be simply listed as "HAP". Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each listed air pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives, including those that do not count towards applicability, when calculating actual emissions. At a minimum, round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values. Attach examples of calculations that illustrates the methodology used.

Air Pollutants (including regulated air pollutants and pollutants for which the source is major)	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx	**0**	**11.9**	**1.1**	
SOx	**0**	**0.01**	**0.01**	
VOC	**0**	**10.1**	**1.0**	
CO	**0**	**64.8**	**6.2**	

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM EMISS - EMISSIONS CALCULATIONS

INSTRUCTIONS: Use this form to calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _**FUG01**

B. Identification and Quantification of Emissions

Instructions: First, list each air pollutant that is either regulated at the unit or present in major amounts. Second, list any other regulated pollutant (for fee calculation) emitted at the unit that have not already been listed. Each HAP added to the list in this step may be simply listed as "HAP". Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each listed air pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives, including those that do not count towards applicability, when calculating actual emissions. At a minimum, round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values. Attach examples of calculations that illustrates the methodology used.

Air Pollutants (including regulated air pollutants and pollutants for which the source is major)	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
VOC	**0**	**10.0**	**43.8**	

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM PTE - POTENTIAL TO EMIT SUMMARY

INSTRUCTIONS: Complete this form once for the facility. You may find it helpful to complete form **EMISS** for each emissions unit before completing this form. For each emissions unit with emissions that count towards applicability, list the emissions unit ID and the PTE for the air pollutants listed below. If there are other air pollutants not listed below for which the source is a major source, provide attachments naming the air pollutant and showing calculation of the total for that pollutant. Round values to the nearest tenth of a ton. Add all values together in each column and enter the total in the space provided at the bottom of the table. Also report these totals in section **J** of form **GIS**.

Emissions Unit ID	Regulated Air Pollutants and Pollutants for which the Source is Major						
	NOx (tons/yr)	VOC (tons/yr)	SO2 (tons/yr)	PM10 (tons/yr)	CO (tons/yr)	Lead (tons/yr)	HAP (tons/yr)
TURB01	**63.5**	**2.2**	**2.4**	**29.7**	**77.3**	**0**	**2.5**
TURB02	**63.5**	**2.2**	**2.4**	**29.7**	**77.3**	**0**	**2.5**
TURB03	**1.4**	**0.1**	**0.1**	**0.7**	**1.7**	**0**	**0.1**
HEAT01	**8.3**	**0.5**	**0.1**	**0.6**	**7.0**	**0**	**0**
EGEN01	**2.6**	**0.1**	**0.3**	**0.1**	**0.6**	**0**	**0**
EGEN02	**2.6**	**0.1**	**0.3**	**0.1**	**0.6**	**0**	**0**
FLAR01	**1.1**	**1.0**	**0.01**	**0**	**6.2**	**0**	**0**
FUG01	**0**	**43.8**	**0**	**0**	**0**	**0**	**0**
TOTALS	143.0	50.0	5.6	60.9	170.7	0	5.1

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM EUD-1 - EMISSIONS UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES

INSTRUCTIONS: Complete this form for each significant emissions unit best described as a fuel combusting unit.

A. General Information

Emissions unit ID **TURB01** Description **SOLAR Titan Low NO_x Turbine**

SIC Code (4-digit) **4491** SCC Code **2-01-002-01**

B. Emissions Unit Description

Primary use **Power Generation** Temporary source ___ Yes **X** No

Manufacturer **SOLAR** Model No. **To Be Determined**

Serial Number **To Be Determined** Installation date **4th Quarter 2008**

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

___ Other (describe) ______

Boiler horsepower rating ______ Boiler steam flow (lb/hr) ______

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___ Spreader stoker ___ Underfeed stoker ___ Overfeed stoker

___ Traveling grate ___ Shaking grate ___ Pulverized, wet bed ___ Pulverized, dry bed

Actual (average) Heat Input **164** MM BTU/hr Maximum design heat input **164** MM BTU/hr

C. Fuel Data

Primary fuel type(s) **Natural Gas** Standby fuel type(s) **N/A**

Instructions: Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (per cf, gal., or lb.)
Natural Gas	**0.00033%**	**0%**	**1050 BTU/scf**

D. Fuel Usage Rates

Instructions: For each fuel described above, enter actual and maximum fuel usage rates on a worst-case hourly and annual basis. Indicate the dimension for the fuel usage rate (e.g., gallons, cords, cubic feet).

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	**0**	**156,194 scf**	**1,368,256,000 scf**

E. Associated Air Pollution Control Equipment

Emissions unit ID __**N/A**__________ Device type __**Dry Low NOx Burners Incorporated**_________

Air pollutant(s) Controlled __**CO, NOx**______________ Manufacturer __**Solar**______________________

Model No. __**N/A** ____________________ Serial No. __**N/A** _____________________

Installation date _____/_____/____ Control efficiency (%) _**N/A** _______.____

Efficiency estimation method ___**25 ppm NOx, 50 ppm CO**____________________________________

F. Ambient Impact Assessment

Instructions: This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit.

Stack height (ft) ___**N/A** __._____ Inside stack diameter (ft) __**N/A** _______._____

Stack temp(^{o}F) _____**N/A** ._____ Design stack flow rate (ACFM) _**N/A** _________.____

Actual stack flow rate (ACFM) __**N/A** __________.____ Velocity (ft/sec) _**N/A** ___________._______

OMB Control No. 2060-0336

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM EUD-1 - EMISSIONS UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES

INSTRUCTIONS: Complete this form for each significant emissions unit best described as a fuel combusting unit.

A. General Information

Emissions unit ID **TURB02** Description **SOLAR Titan Low NO_x Turbine**

SIC Code (4-digit) **4491** SCC Code **2-01-002-01**

B. Emissions Unit Description

Primary use **Power Generation** Temporary source ___ Yes **X** No

Manufacturer **SOLAR** Model No. **To Be Determined**

Serial Number **To Be Determined** Installation date **4th Quarter 2008**

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

___ Other (describe) ____________________

Boiler horsepower rating ____________ Boiler steam flow (lb/hr) ____________

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___ Spreader stoker ___ Underfeed stoker ___ Overfeed stoker

___ Traveling grate ___ Shaking grate ___ Pulverized, wet bed ___ Pulverized, dry bed

Actual (average) Heat Input **164** MM BTU/hr Maximum design heat input **164** MM BTU/hr

C. Fuel Data

Primary fuel type(s) **Natural Gas** Standby fuel type(s) **N/A**

Instructions: Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (per cf, gal., or lb.)
Natural Gas	**0.00033%**	**0%**	**1050 BTU/scf**

D. Fuel Usage Rates

Instructions: For each fuel described above, enter actual and maximum fuel usage rates on a worst-case hourly and annual basis. Indicate the dimension for the fuel usage rate (e.g., gallons, cords, cubic feet).

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	**0**	**156,194 scf**	**1,368,256,000 scf**

E. Associated Air Pollution Control Equipment

Emissions unit ID __**N/A**__________ Device type __**Dry Low NOx Burners Incorporated**_________

Air pollutant(s) Controlled __**CO, NOx**______________ Manufacturer __**Solar**______________________

Model No. __**N/A** ____________________ Serial No. __**N/A** _____________________

Installation date _____/_____/____ Control efficiency (%) _**N/A** _______.____

Efficiency estimation method ___**25 ppm NOx, 50 ppm CO**___________________________________

F. Ambient Impact Assessment

Instructions: This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit.

Stack height (ft) ___**N/A** __._____ Inside stack diameter (ft) __**N/A** _______._____

Stack temp(^{o}F) ____**N/A** ._____ Design stack flow rate (ACFM) _**N/A** _________.____

Actual stack flow rate (ACFM) __**N/A** ________ Velocity (ft/sec) _**N/A** ___________._______

OMB Control No. 2060-0336

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM EUD-1 - EMISSIONS UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES

INSTRUCTIONS: Complete this form for each significant emissions unit best described as a fuel combusting unit.

A. General Information

Emissions unit ID **TURB03** Description **SOLAR Titan Low NO_x Turbine**

SIC Code (4-digit) **4491** SCC Code **2-01-002-01**

B. Emissions Unit Description

Primary use **On site Electric Generation** Temporary source ___ Yes __X__ No

Manufacturer **SOLAR** Model No. **To Be Determined**

Serial Number **To Be Determined** Installation date **4th Quarter 2008**

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

___ Other (describe) ______________________

Boiler horsepower rating ______________ Boiler steam flow (lb/hr) ______________

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___ Spreader stoker ___ Underfeed stoker ___ Overfeed stoker

___ Traveling grate ___ Shaking grate ___ Pulverized, wet bed ___ Pulverized, dry bed

Actual (average) Heat Input **3.59** MM BTU/hr Maximum design heat input **164** MM BTU/hr

C. Fuel Data

Primary fuel type(s) **Natural Gas** Standby fuel type(s) **N/A**

Instructions: Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (per cf, gal., or lb.)
Natural Gas	**0.00033%**	**0%**	**1050 BTU/scf**

D. Fuel Usage Rates

Instructions: For each fuel described above, enter actual and maximum fuel usage rates on a worst-case hourly and annual basis. Indicate the dimension for the fuel usage rate (e.g., gallons, cords, cubic feet).

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	**0**	**156,194 scf**	**29,989,248 scf**

E. Associated Air Pollution Control Equipment

Emissions unit ID __**N/A**__________ Device type __**Dry Low NOx Burners Incorporated**_________

Air pollutant(s) Controlled __**CO, NOx**______________ Manufacturer __**Solar**_______________________

Model No. __**N/A** _____________________ Serial No. __**N/A** ______________________

Installation date _____/_____/____ Control efficiency (%) _**N/A** _______.____

Efficiency estimation method ___**25 ppm NOx, 50 ppm CO**____

F. Ambient Impact Assessment

Instructions: This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit.

Stack height (ft) ___**N/A** __._____ Inside stack diameter (ft) __**N/A** _______._____

Stack temp(^{o}F) ____**N/A** ._____ Design stack flow rate (ACFM) _**N/A** _________.____

Actual stack flow rate (ACFM) __**N/A** ________ Velocity (ft/sec) _**N/A** ___________._______

OMB Control No. 2060-0336

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM EUD-1 - EMISSIONS UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES

INSTRUCTIONS: Complete this form for each significant emissions unit best described as a fuel combusting unit.

A. General Information

Emissions unit ID **HEAT01** Description **Sales Gas Heater**

SIC Code (4-digit) __**4491**________ SCC Code **1-02-006-02**_

B. Emissions Unit Description

Primary use __**Gas Heater**_________ Temporary source ___ Yes __**X**_ No

Manufacturer __**To Be Determined**__ Model No. __**To Be Determined**_______________

Serial Number __**To Be Determined**_______________ Installation date **4th Quarter 2008**_

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

___ Other (describe) ____

Boiler horsepower rating ___________________ Boiler steam flow (lb/hr) ______________________

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___ Spreader stoker ___ Underfeed stoker ___ Overfeed stoker

___ Traveling grate ___ Shaking grate ___ Pulverized, wet bed ___ Pulverized, dry bed

Actual (average) Heat Input __**20.0**____ MM BTU/hr Maximum design heat input __**20.0**___ MM BTU/hr

C. Fuel Data

Primary fuel type(s) _______**Natural Gas**________ Standby fuel type(s) _______**N/A**______________

Instructions: Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (per cf, gal., or lb.)
Natural Gas	**0.00033%**	**0%**	**1050 BTU/scf**

D. Fuel Usage Rates

Instructions: For each fuel described above, enter actual and maximum fuel usage rates on a worst-case hourly and annual basis. Indicate the dimension for the fuel usage rate (e.g., gallons, cords, cubic feet).

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	**0**	**19,048 scf**	**166,857,143 scf**

E. Associated Air Pollution Control Equipment

Emissions unit ID ___N/A________ Device type __N/A ______________________________________

Air pollutant(s) Controlled ___N/A______________ Manufacturer ____N/A____________________

Model No. ___N/A_________________ Serial No. ___N/A_________________

Installation date _____/_____/____ Control efficiency (%) _N/A___________

Efficiency estimation method __N/A____

F. Ambient Impact Assessment

Instructions: This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit.

Stack height (ft) __N/A ______________ Inside stack diameter (ft) __N/A_____________

Stack temp(^{o}F) __N/A ______________ Design stack flow rate (ACFM) __N/A____________

Actual stack flow rate (ACFM) __N/A ___________.____ Velocity (ft/sec) __N/A ___________._______

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM EUD-1 - EMISSIONS UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES

INSTRUCTIONS: Complete this form for each significant emissions unit best described as a fuel combusting unit.

A. General Information

Emissions unit ID **EGEN01** Description **Emergency Generator 1100 hp**

SIC Code (4-digit) **4491** SCC Code **2-01-001-02**

B. Emissions Unit Description

Primary use **Emergency Generation** ______________________ Temporary source ___ Yes **X** No

Manufacturer **To Be Determined** Model No. **To Be Determined**

Serial Number **To Be Determined** Installation date **4th Quarter 2008**

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

___ Other (describe) ____

Boiler horsepower rating ___________________ Boiler steam flow (lb/hr) ______________________

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___ Spreader stoker ___ Underfeed stoker ___ Overfeed stoker

___ Traveling grate ___ Shaking grate ___ Pulverized, wet bed ___ Pulverized, dry bed

Actual (average) Heat Input **0.17** MM BTU/hr Maximum design heat input **7.70** MM BTU/hr

C. Fuel Data

Primary fuel type(s) **Diesel** Standby fuel type(s) **N/A**

Instructions: Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (per cf, gal., or lb.)
Diesel	**0.4%**	**0%**	**145,000 BTU/gal**

D. Fuel Usage Rates

Instructions: For each fuel described above, enter actual and maximum fuel usage rates on a worst-case hourly and annual basis. Indicate the dimension for the fuel usage rate (e.g., gallons, cords, cubic feet).

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Diesel	**0**	**53.13 gal**	**2,763 gal**

E. Associated Air Pollution Control Equipment

Emissions unit ID ___N/A_________ Device type ______N/A ___________________________________

Air pollutant(s) Controlled ____N/A ___________________ Manufacturer _____N/A ________________

Model No. ____N/A ____________________ Serial No. _____N/A ____________________

Installation date _____/_____/____ Control efficiency (%) _____N/A _____._____

Efficiency estimation method _______N/A ____

F. Ambient Impact Assessment

Instructions: This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit.

Stack height (ft) ____N/A ________._____ Inside stack diameter (ft) ____N/A _______._____

Stack temp(^oF) ____N/A ________._____ Design stack flow rate (ACFM) _____N/A _______._____

Actual stack flow rate (ACFM) ___N/A ___________.____ Velocity (ft/sec) ____N/A __________.________

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM EUD-1 - EMISSIONS UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES

INSTRUCTIONS: Complete this form for each significant emissions unit best described as a fuel combusting unit.

A. General Information

Emissions unit ID **EGEN02** Description **Emergency Generator 1100 hp**

SIC Code (4-digit) **4491** SCC Code **2-01-001-02**

B. Emissions Unit Description

Primary use **Emergency Generation** ____________ Temporary source ___ Yes **X** No

Manufacturer **To Be Determined** Model No. **To Be Determined**

Serial Number **To Be Determined** Installation date **4th Quarter 2008**

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

___ Other (describe) ____________________

Boiler horsepower rating ____________ Boiler steam flow (lb/hr) ____________

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___ Spreader stoker ___ Underfeed stoker ___ Overfeed stoker

___ Traveling grate ___ Shaking grate ___ Pulverized, wet bed ___ Pulverized, dry bed

Actual (average) Heat Input **0.17** MM BTU/hr Maximum design heat input **7.70** MM BTU/hr

C. Fuel Data

Primary fuel type(s) **Diesel** Standby fuel type(s) **N/A**

Instructions: Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (per cf, gal., or lb.)
Diesel	**0.4%**	**0%**	**145,000 BTU/gal**

D. Fuel Usage Rates

Instructions: For each fuel described above, enter actual and maximum fuel usage rates on a worst-case hourly and annual basis. Indicate the dimension for the fuel usage rate (e.g., gallons, cords, cubic feet).

Fuel Type	Annual Actual Usage	Maximum Usage Hourly	 Annual
Diesel	**0**	**53.13 gal**	**2,763 gal**

E. Associated Air Pollution Control Equipment

Emissions unit ID ___N/A_________ Device type _____N/A ___________________________________

Air pollutant(s) Controlled ___N/A ___________________ Manufacturer ____N/A ________________

Model No. ___N/A ____________________ Serial No. ____N/A ____________________

Installation date _____/_____/____ Control efficiency (%) ____N/A ____.____

Efficiency estimation method ______N/A ____

F. Ambient Impact Assessment

Instructions: This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit.

Stack height (ft) ___N/A _______._____ Inside stack diameter (ft) ___N/A ______._____

Stack temp(^oF) ___N/A _______._____ Design stack flow rate (ACFM) ____N/A ______.____

Actual stack flow rate (ACFM) __N/A __________.____ Velocity (ft/sec) ___N/A _________._______

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM EUD-1 - EMISSIONS UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES

INSTRUCTIONS: Complete this form for each significant emissions unit best described as a fuel combusting unit.

A. General Information

Emissions unit ID **FLAR01** Description **Flare**

SIC Code (4-digit) __**4491**________ SCC Code _**3-06-009-03**_______

B. Emissions Unit Description

Primary use **Emergency Flaring**____________ Temporary source ___ Yes __**X**_ No

Manufacturer __**To Be Determined**________ Model No. __**To Be Determined**_______

Serial Number __**To Be Determined**_____ Installation date **4th Quarter 2008**__

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

___ Other (describe) ____

Boiler horsepower rating __________________ Boiler steam flow (lb/hr) _____________________

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___ Spreader stoker ___ Underfeed stoker ___ Overfeed stoker

___ Traveling grate ___ Shaking grate ___ Pulverized, wet bed ___ Pulverized, dry bed

Actual (average) Heat Input __**3.8**____ MM BTU/hr Maximum design heat input _**175**_ MM BTU/hr

C. Fuel Data

Primary fuel type(s) _______**Natural Gas**________ Standby fuel type(s) ______________________

Instructions: Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (per cf, gal., or lb.)
Vaporized or Boil-off Gas	**0.00033%**	**0%**	**1050 BTU/scf**

D. Fuel Usage Rates

Instructions: For each fuel described above, enter actual and maximum fuel usage rates on a worst-case hourly and annual basis. Indicate the dimension for the fuel usage rate (e.g., gallons, cords, cubic feet).

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	**0**	**166,667 scf**	**32,000,064 scf**

E. Associated Air Pollution Control Equipment

Emissions unit ID ___**N/A**_________ Device type ______**N/A** ____________________________________

Air pollutant(s) Controlled ___**N/A** ___________________ Manufacturer _____**N/A** ________________

Model No. ___**N/A** ____________________ Serial No. _____**N/A** ____________________

Installation date _____/_____/____ Control efficiency (%) _____**N/A** ____.____

Efficiency estimation method _______**N/A** ____

F. Ambient Impact Assessment

Instructions: This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit.

Stack height (ft) ___**N/A** _______._____ Inside stack diameter (ft) ___**N/A** ______._____

Stack temp(^{o}F) ___**N/A** _______._____ Design stack flow rate (ACFM) _____**N/A** ______.____

Actual stack flow rate (ACFM) __**N/A** __________.____ Velocity (ft/sec) ____**N/A** _________._______

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM EUD-2 - EMISSIONS UNIT DESCRIPTION FOR VOC EMITTING SOURCES

INSTRUCTIONS: Complete this form for each significant emissions unit best described as a VOC emitting unit.

A. General Information

Emissions unit ID **FUG01** Description **Fugitive Emissions**

SIC Code (4-digit) **4491** SCC Code ________

B. Emissions Unit Description

Equipment type **Fugitive Emissions** Temporary source: ___ Yes _X_ No

Manufacturer **N/A** Model No. **N/A**

Serial No. **N/A** Installation date _____/_____/_____

Articles being coated or degreased **N/A**

Application method **N/A**

Overspray (surface coating) (%) **N/A** Drying method **N/A**

No. of dryers **N/A** Tank capacity (degreasers) (gal) **N/A**

C. Associated Air Pollution Control Equipment

Emissions unit ID **N/A** Device Type **N/A**

Manufacturer **N/A** Model No. **N/A**
Serial No. **N/A** Installation date _____/_____/_____

Control efficiency (%) **N/A** .___ Capture efficiency (%) **N/A** .___

Air pollutant(s) controlled **N/A** Efficiency estimation method **N/A**

D. Ambient Impact Assessment

Instructions: This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit.

Stack height (ft) **N/A** ._____ Inside stack diameter (ft) **N/A** ._____

Stack temp(^{o}F) **N/A** ._____ Design stack flow rate (ACFM) **N/A** .____

Actual stack flow rate (ACFM) **N/A** .____ Velocity (ft/sec) **N/A** .______

E. VOC-containing Substance Data

Instructions: List each VOC-containing substance consumed, processed or produced at the emissions unit that is emitted into the atmosphere. In the name column, if providing a brand name of a substance, include the name of the manufacture; if the substance contains HAP, list the constituent HAP.

VOC-Containing Substance Name(e.g., Chemical or Brand Name)	CAS No. (if available)	Substance Type (e.g., coating, solvent, ink, etc.)	Actual Usage (gal/yr)	Maximum Usage		VOC Content (lb/gal)
				gal/day	gal/year	
Natural Gas Fugitives		**Natural Gas**	**N/A**	**N/A**	**N/A**	**N/A**

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM EUD-3 - EMISSION UNIT DESCRIPTION FOR PROCESS SOURCES

INSTRUCTIONS: Complete this form for each significant emission unit that is not primarily a VOC emitting unit or a fuel combustion unit.

A. General Information

Emissions unit ID ___________ Description ___________________________________

SIC Code (4-digit) __________ SCC Code ________

B. Emissions Unit Description

Primary use or equipment type ________________________________ Temporary source: ___ Yes ___ No

Manufacturer _________________________________ Model No. ___________________________________

Serial No. ____________________________________ Installation date _____/_____/_____

Raw materials ____

Finished products ____

C. Activity or Production Rates

Instructions: Enter actual and maximum activity rates for the materials that are processed or the number of activities performed. Actual rates are the rates that will be used to calculate actual emissions for fee purposes. Maximum rates are the rates used to calculate potential to emit for applicability purposes.

Activity or Production Rate	Amount/Hour	Amount/Year
Actual Rate		
Maximum rate		

D. Associated Air Pollution Control Equipment

Emissions unit ID ____________ Device Type ____

Manufacturer _________________________________ Model No. ___________________________________

Serial No. ____________________________________ Installation date _____/_____/_____

Control efficiency (%) _________.___ Capture efficiency (%) ________.___

Air pollutant(s) controlled _______________ Efficiency estimation method _____________________________

E. Ambient Impact Assessment

Instructions: This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit.

Stack height (ft) __________._____ Inside stack diameter (ft) _________._____

Stack temp(^{o}F) __________._____ Design stack flow rate (ACFM) __________.____

Actual stack flow rate (ACFM) ____________.____ Velocity (ft/sec) ____________._______

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM FEE - FEE CALCULATION WORKSHEET

INSTRUCTIONS: Use this form to initially or thereafter on a annual basis report actual emissions and calculate fees, consistent with § 71.9.

A. General Information

Instructions: All sources must complete this section.

Type of fee calculation worksheet (Check one):

X Initial ___ Annual

Deadline for submitting fee calculation worksheet ______/______/__________

For initial fee calculation worksheets, emissions are based on (Check one):

___ Actual emissions for the preceding year

___ Estimates of actual emissions for the preceding year

_X_ Estimates of actual emissions for the current year

If you checked the last box, provide the date the facility commenced operations ____01/2009

B. Source Information

Instructions: Complete this section only if you are not applying for a permit at this time.

Source or facility name ______________________________

Mailing address: Street or P.O. Box ______________________________

City ______________________ State _____ ZIP ________ - ______

Contact person ______________________ Title ______________________

Telephone (______) ______ - ________ Ext. ______ Part 71 permit no. ______________

C. Certification of Truth, Accuracy and Completeness

Instructions: This form must be signed by the responsible official.

I certify under penalty of law that, based on information and belief formed after reasonable inquiry, the statements and information contained in this fee calculation worksheet (and attachments) are true, accurate and complete.

Name (signed) A. Y. Noojin III

Name (typed) A. Y. Noojin, III Date: 10 / 21 / 03

D. Annual Emissions Report for Fee Calculation Purposes -- Non-HAP

Instructions: Report calendar-year actual emissions of regulated pollutants (for fee calculation) except for HAP, and use for both initial and annual fee calculation purposes. Section E is used to report actual emissions of HAP. Quantify all actual emissions, including fugitives, but do not include insignificant emissions. Round to the nearest tenth of a ton. Sum the emissions in each column and enter a subtotal at the bottom of the page. If a subtotal is greater than 4,000 tons, enter 4,000. Submit attachments showing calculations.

This data is for __**2003**__________ (year).

Emissions Unit ID	Actual Emissions (Tons/Year)					
	NOx	VOC	SO2	PM10	Lead	Other
TURB01	**0**	**0**	**0**	**0**	**0**	**0**
TURB02	**0**	**0**	**0**	**0**	**0**	**0**
TURB03	**0**	**0**	**0**	**0**	**0**	**0**
HEAT01	**0**	**0**	**0**	**0**	**0**	**0**
EGEN01	**0**	**0**	**0**	**0**	**0**	**0**
EGEN02	**0**	**0**	**0**	**0**	**0**	**0**
FLAR01	**0**	**0**	**0**	**0**	**0**	**0**
FUG01	**0**	**0**	**0**	**0**	**0**	**0**

SUBTOTALS ___**0**_________ _____**0**_______ ______**0**_____ _______**0**_____ ______**0**______ ______**0**_____

E. Annual Emissions Report for Fee Calculation Purposes -- HAP

Instructions: Use the first table below to identify each HAP meeting the definition of regulated pollutant (for fee calculation) emitted at the facility, identify the CAS number, and assign a unique identifier for use in the second table in this section. When assigning identifier codes, please use "HAP1" for the first, "HAP2" for the second, and so on.

Name of HAP	CAS No.	Identifier
Formaldehyde	**50000**	HAP **1**____
		HAP____
		HAP____
		HAP ____
		HAP ____
		HAP ____
		HAP ____
		HAP ____

Instructions: Now report the actual emissions of each individual HAP identified above. Use the identifiers assigned in the table above to identify each HAP. Include all emissions, including fugitives, but do not include insignificant emissions. Report emissions values to the nearest tenth of a ton. Sum the emissions in each column and show a subtotal at the bottom of the page. If a subtotal is greater than 4,000 tons, enter 4,000. Submit attachments showing calculations.

This data is for __**2003**________ (year)

Emissions Unit ID	Actual Emissions (Tons/Year)							
	HAP**1**____	HAP____	HAP____	HAP____	HAP____	HAP____	HAP____	HAP____
TURB01	**0**							
TURB02	**0**							
TURB03	**0**							
SUBTOTALS	___**0**_____	________	________	________	________	________	________	________

F. Fee Calculation Worksheet

Instructions: This section is used to calculate the total fee owed for initial application or annual fee payment purposes. Unless otherwise instructed to proceed to a different line, always proceed to the next line. If you do not need to reconcile estimated against actual emissions, complete the part for emissions calculation (lines 1 - 5) and then proceed to the part for fee calculation (lines 21 - 26). A final permit or permit revision will not be issued until all fees, interest, and penalties assessed against a source are paid. In addition, the initial application for a source will not be found complete unless the source pays all fees owed.

EMISSIONS CALCULATION

1. Sum the subtotals from section D of this form and enter the result on this line. ______0__________.___

2. Sum the subtotals from section E of this form and enter the result on this line. ______0__________.___

3. Total lines 1 and 2 and enter the result on this line. ______0__________.___

4. Sources are not required to pay fees twice for the same emissions [see § 71.9(c)(5)(ii)]. Enter the amount of emissions that were counted twice. Attach supplementary information identifying the emissions units where double counting has occurred and explain why double counting has occurred. If there has been no double counting enter "0." ______0________.___

5. Subtract the amount on line 4 from the amount on line 3, round to the nearest ton, and enter the result on this line. ________0____________

RECONCILIATION OF ESTIMATED EMISSIONS AGAINST ACTUAL EMISSIONS (WHEN INITIAL ESTIMATES WERE BASED ON THE CURRENT CALENDAR YEAR)

Only complete lines 6 - 10 if you are now preparing the first annual fee worksheet and the initial fee worksheet included estimated emissions for the current calendar year. See §§ 71.9(e)(2) and 71.9(h)(3). Otherwise skip this part of the form and proceed to the next part of the form (starting at line 11) or to the fee calculation part of the form (starting at line 21).

6. Enter the total estimated emissions previously reported on line 5 of the initial fee calculation worksheet. These are estimated emissions for the year that the initial fee worksheet was submitted. __________0___________

7. If the amount on line 5 of this form is greater than the amount on line 6, subtract line 6 from line 5, and enter the result on this line. Otherwise enter "0." __________0___________

8. If the amount on line 6 is greater than the amount on line 5, subtract line 5 from line 6, and enter the result on this line. Otherwise enter "0." __________0___________

9. Multiply the amount on line 7 by (last year's $/ton amount[1]), and enter the result on this line. This is the amount of underpayment. Go to line 21. $_________0____.______

10. Multiply the amount on line 8 by (last year's $/ton amount), and enter the result on this line. This is the amount of overpayment. Go to line 21. $_________0____.______

[1] $/ton amounts to be determined at the time of program implementation, see § 71.9(c)(1) - (3).

RECONCILIATION OF ESTIMATED EMISSIONS AGAINST ACTUAL EMISSIONS (WHEN INITIAL ESTIMATES WERE BASED ON THE PRECEDING CALENDAR YEAR)

Only complete lines 11 - 20 if you are now preparing the first annual fee worksheet and the initial fee worksheet included estimated emissions for the preceding calendar year. See §§ 71.9(f)(2) and 71.9(h)(3). If you must complete this part of the form, you must also submit annual emission reports (sections D and E) for the year preceding initial worksheet submittal. Otherwise skip this part of the form and proceed to the fee calculation part of the form (lines 21 through 26).

11. Sum the subtotals from section D for the calendar year preceding initial fee worksheet submittal and enter the result on this line. __________0______.___

12. Sum the subtotals from section E for the calendar year preceding initial fee worksheet submittal and enter the result on this line. __________0______.___

13. Total lines 11 and 12 and enter the result on this line. This is the total actual emissions for the calendar year preceding initial fee worksheet submittal. __________0______.___

**RECONCILIATION OF ESTIMATED EMISSIONS AGAINST ACTUAL EMISSIONS
(WHEN INITIAL ESTIMATES WERE BASED ON THE PRECEDING CALENDAR YEAR)
--- CONTINUED ---**

14.	Sources are not required to pay fees twice for the same emissions [see § 71.9(c)(5)(ii)]. Enter the amount of emissions (actual emissions for the year preceding initial worksheet submittal) that were counted twice. Attach supplementary information identifying the emissions units where double counting has occurred and explain why double counting has occurred. If there has been no double counting enter "0."	0 .
15.	Subtract the amount on line 14 from the amount on line 13, round to the nearest ton, and enter the result on this line.	0
16.	Enter the total estimated emissions previously reported on line 5 of the initial fee calculation worksheet. These are estimated emissions for the calendar year preceding initial fee worksheet submittal.	0
17.	If the amount on line 15 is greater than the amount on line 16, subtract line 16 from line 15, and enter the result on this line. Otherwise enter "0."	0
18.	If the amount on line 16 is greater than the amount on line 15, subtract line 15 from line 16, and enter the result on this line. Otherwise enter "0."	0
19.	Multiply the amount on line 17 by (last year's $/ton amount[1]) and enter the result on this line. This is the amount of underpayment.	$ 0 .
20.	Multiply the amount on line 18 by (last year's $/ton amount) and enter the result on this line. This is the amount of overpayment.	$ 0 .

FEE CALCULATION

21.	Multiply the amount on line 5 on this form by (this year's $/ton amount) and enter the result on this line.	$ 0 .
22.	If you have reconciled estimated against actual emissions, enter the underpayment from line 9 or 19 on this line. Otherwise enter "0."	$ 0 .
23.	If you have reconciled estimated against actual emissions, enter the overpayment from line 10 or 20 on this line. Otherwise enter "0."	$ 0 .
24.	If the amount on line 22 is greater than "0," add this amount to the amount on line 21 and enter the result on this line. If the amount on line 23 is greater than "0," subtract this amount from the amount on line 21 and enter the result on this line. Otherwise enter the amount on line 21 on this line. This is the fee adjusted for reconciliation.	$ 0 .
25.	If your account was credited for fee assessment error [see § 71.9(j)] since the last time you submitted a fee calculation worksheet, enter the amount of the credit on this line. Otherwise enter "0."	$ 0 .
26.	Subtract the amount on line 25 from the amount on line 24 and enter the result on this line. Stop here. This is the total fee amount that you must remit to EPA.	$ 0 .

PENALTIES AND INTEREST

Payment received later than the due date shall be assessed interest and, in certain cases, penalty charges. If payment is late, do not calculate penalties and interest at this time. The permitting authority will assess these and mail you an invoice.

OMB Control No. 2060-0336

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM FF - FEE FILING

Instructions: Complete this form once for the part 71 source (facility) and send it to the appropriate lockbox bank address, along with full payment. This form required at time of initial, and thereafter, annual fee payment.

A. Source or Facility Name **Gulf Landing**

B. Mailing Address and Contact Person:

Street or P.O. Box **1301 McKinney, Suite 700**

City **Houston** State **TX** ZIP **77010** - ______

Contact Person: **Larry Jensen** Title **Director, Regulatory Affairs**

Telephone (**713**) **230** - **3134** Ext. ____________

C. Total Fee Payment Remitted: $ **0** ________________.______

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

FORM I-COMP - INITIAL COMPLIANCE PLAN & COMPLIANCE CERTIFICATION

INSTRUCTIONS: There are 3 pages to this form. On this page, complete Sections A, B, and C for each applicable requirement. If different portions of an applicable requirement or compliance methods vary from unit to unit, prepare a separate form for each unique set of requirements, methods, and units. For compliance plan purposes, assume permit issuance will occur by March 22, 2001, unless you are not required to submit an application until after March 22, 2000, in which case assume issuance will occur no later than 18 months after submittal.

A. COMPLIANCE STATUS OF EACH APPLICABLE REQUIREMENT (Describe each applicable requirement and determine its compliance status)

Cite and Describe the Applicable Requirement	Unit ID(s):	Compliance status at time of application :
NSPS – 40 CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines – 40 CFR 60.332(a)(1) Standards for Nitrogen Dioxide:-shall not discharge any gases which contain nitrogen oxide in excess of: STD =[(0.0075)(14.4)/(Y)]+ F - **Where Y is equal to manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour) or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.** - **-Where F is equal to the NOx emission allowance for fuel bound nitrogen as defined in 40 CFR 60.332(a)(3).**	**TURB01** **TURB02** **TURB03**	_X__ In Compliance ___ Not In Compliance

B. METHODS USED TO DETERMINE COMPLIANCE (Describe all methods you used to determine compliance with this requirement)

1) Monitor nitrogen content of fuel being fired in the turbine by documentation of records of fuel composition received from each LNG carrier during unloading and upon receipt of LNG.

2) Compute Nitrogen oxides emission rate utilizing equation 40 CFR 60.335 (c)(1).

3) Conduct initial testing of NOx and O2 and any subsequent testing under requirements of 40 CFR Part 60, Appendix A, Method 20, at loading specified under 40 CFR Part 60.335(c)(3).

4) Annual compliance certification.

C. COMPLIANCE PLAN STATEMENTS (Respond to one of these statements for this applicable requirement)

1.	2.	3.
If in compliance at this time, I will continue to comply. __X_ Yes _____ No	If not in compliance at this time, I will be in compliance by expected date of permit issuance. ___ Yes ___ No Expected Date _____/_____/_____	For future-effective requirements. I will meet this requirement on a timely basis. _X___ Yes _____ No

A. COMPLIANCE STATUS OF EACH APPLICABLE REQUIREMENT (Describe each applicable requirement and determine its compliance status)

Cite and Describe the Applicable Requirement	Unit ID(s):	Compliance status at time of application :
NSPS – 40 CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines – 40 CFR 60.333(b) Standards for Sulfur Dioxide: shall not burn any fuel which contains sulfur in excess of 0.8 percent by weight.	**TURB01** **TURB02** **TURB03**	_X_ In Compliance ___ Not In Compliance

B. METHODS USED TO DETERMINE COMPLIANCE (Describe all methods you used to determine compliance with the requirement)

1) Monitor content of sulfur in fuel being fired in turbine by documentation of records of fuel composition received from each LNG carrier during unloading and upon receipt of LNG.

2) Determine compliance as indicated in 40 CFR 60.335(c).

3) Annual compliance certification.

C. COMPLIANCE PLAN STATEMENTS (Respond to one of these statements for this applicable requirement)

1.	2.	3.
If in compliance at this time, I will continue to comply. __X_ Yes _____ No	If not in compliance at this time, I will be in compliance by expected date of permit issuance. ___ Yes ___ No Expected Date _____/_____/____	For future-effective requirements. I will meet this requirement on a timely basis. _X___ Yes _____ No

D. ADDITIONAL INFORMATION FOR COMPLIANCE PLAN STATEMENT #2

Complete this section if you answered "YES" to the second statement in Section C. Complete this section for each such applicable requirement. Identify the applicable requirement and describe the actions you will take prior to permit issuance to come into compliance.

1. **Applicable Requirement.**

Unit(s) ____________________ Applicable Requirement ____

2. **Narrative Description of how Source will Achieve Compliance.**

____

____

E. SCHEDULE OF COMPLIANCE

Complete this section if you answered "NO" to any of the statements in Section C. Complete this section for each such applicable requirement. Identify the emission unit and the applicable requirement, the reasons for noncompliance, and describe how the source will achieve compliance. If there are consent decrees or administrative orders that apply to this requirement, attach a copy of them to this form. Finally, all sources required to complete this section must include a detailed schedule of compliance.

1. **Applicable Requirement**.

Unit(s) ____________________ Applicable Requirement ____

2. **Reason for Noncompliance**. Briefly explain why the source will not be in compliance at time of permit issuance or not meet future-effective requirements on a timely basis.)

____

3. **Narrative Description of how Source will Achieve Compliance**. Briefly explain what you will do to bring the source into compliance with this requirement.

____

____

4. **Consent Decrees or Administrative Orders**. Please attach a copy of any judicial consent decrees or administrative orders for this applicable requirement.

5. **Schedule of Compliance**. Provide a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance, including a date for final compliance.

Remedial Measure or Action	Date to be Achieved

INSTRUCTIONS: Complete sections E, F, and G once for each facility.

F. SCHEDULE FOR SUBMISSION OF PROGRESS REPORTS

This section need only be prepared if you are required to submit one or more schedules of compliance (by completing section E) or if an applicable requirement requires you to submit a progress report. For most sources, the time frame for submittal of progress reports will be at least every 6 months. One progress report may include information on multiple schedules of compliance.

Contents of Progress Report (describe)

____

Report Starting date ____/____/___ Submittal Frequency _______________

Contents of Progress Report (describe)

____

Report Starting date ____/____/___ Submittal Frequency _______________

G. SCHEDULE FOR SUBMISSION OF COMPLIANCE CERTIFICATIONS

This section must be prepared by every source. Indicate how often you are required to submit compliance certifications after your permit is issued and when the first one will be submitted. Compliance certifications are required to be submitted at least once per year during the term of the permit.

Frequency of submittal __**Annual**____ Beginning _**01/2010**_ **(or one year after operations commence, whichever is earlier)**__

H. COMPLIANCE STATUS FOR ENHANCED MONITORING AND COMPLIANCE CERTIFICATION REQUIREMENTS

This section of the form must be completed for every source. Indicate compliance status for the requirement as a whole (to certify compliance with the requirement as a whole, you must be able to certify compliance with each individual requirement that can be categorized under this designation).

Enhanced Monitoring Requirements: __**X**__ In Compliance ____ Not In Compliance

Compliance Certification Requirements: __**X**__ In Compliance ____ Not In Compliance

OMB Control No. 2060-0336

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR FEDERAL OPERATING PERMIT, 40 CFR PART 71

APPLICATION FORM CTAC - CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS BY RESPONSIBLE OFFICIAL

INSTRUCTIONS: One copy of this form must be completed, signed, and sent with each submission of documents (i.e., application forms, including any updates to applications), and for every document required by a part 71 permit (e.g., annual compliance certification, 6-month monitoring reports, progress reports, and notices required by the terms of a part 71 permit).

Responsible Official. Identify the responsible official and provide contact information.

Name: (Last) **Noolin, III** (First) **A.** (Middle) **Y.**

Title **President**

Street or Post Office Box **1301 McKinney, Suite 700**

City **Houston** State **TX** ZIP **77010** - ____

Telephone (**713**) **230** - **3525** Ext. ____ Facsimile (___) ___ - ___

Certification of Truth, Accuracy and Completeness. The Responsible Official must sign this statement.

I certify under penalty of law that, based on information and belief formed after reasonable inquiry, the statements and information contained in these documents are true, accurate and complete.

Name (signed) A. Y. Noolin III

Name (printed or typed) **A. Y. Noolin, III** Date: 10 / 21 / 03

APPENDIX B – HAZARDOUS AIR POLLUTANT (HAP) EMISSION CALCULATIONS

Table B-1. HAP Emissions Summary

Equipment	Estimated HAP Emissions (tpy)					
	All HAPS	Formaldehyde	Benzene	Toluene	Xylenes	Acetaldehyde
Turbines (Normal)	5.49	5.04	0.02	0.19	0.09	0.06
Turbine (Standby)	0.06	0.06	1.89E-04	2.05E-03	1.01E-03	6.30E-04
FW Drivers	1.75E-03	3.16E-05	3.11E-04	1.13E-04	7.73E-05	1.01E-05
Emergency Generators	6.45E-03	1.17E-04	1.15E-03	4.16E-04	2.85E-04	3.73E-05
Cranes	1.19E-03	2.18E-04	1.72E-04	7.55E-05	5.26E-05	1.42E-04
Gas Heater	0.94	6.26E-03	1.75E-04	2.84E-04		
TOTAL	**6.50**	**5.10**	**0.02**	**0.19**	**0.09**	**0.06**

Table B-2. HAP Emissions from Turbines (Normal)

Process Equipment:	Gas Turbine	(Full-time Operation)
Unit Rating:	16,400	HP
Fuel Type:	Natural Gas	
Fuel Heat Content:	1,050	Btu/SCF
Fuel Usage Factor:	9.524	SCF/HP-hr
Heat Input:	164.00	MMBtu/hr
Hourly Fuel Usage:	156,194	SCF/hr
Annual Operating Hours:	8760	hr/yr
Annual Fuel Usage:	1,368,255,936	SCF/yr

HAP Constituent	Emission Factor[a] lb/MMBtu	Air Emissions					
		1 Gas Turbine			2 Gas Turbines		
		lb/hr	lb/yr	tpy	lb/hr	lb/yr	tpy
1,3-Butadiene	4.30E-07	7.05E-05	6.18E-01	3.09E-04	1.41E-04	1.24E+00	6.18E-04
Acetaldehyde	4.00E-05	6.56E-03	5.75E+01	2.87E-02	1.31E-02	1.15E+02	5.75E-02
Acrolein	6.40E-06	1.05E-03	9.19E+00	4.60E-03	2.10E-03	1.84E+01	9.19E-03
Benzene	1.20E-05	1.97E-03	1.72E+01	8.62E-03	3.94E-03	3.45E+01	1.72E-02
Ethylbenzene	3.20E-05	5.25E-03	4.60E+01	2.30E-02	1.05E-02	9.19E+01	4.60E-02
Formaldehyde[b]	1.59E-02	5.75E-01	5.04E+03	2.52E+00	1.15E+00	1.01E+04	5.04E+00
Naphthalene	1.30E-06	2.13E-04	1.87E+00	9.34E-04	4.26E-04	3.74E+00	1.87E-03
PAH	2.20E-06	3.61E-04	3.16E+00	1.58E-03	7.22E-04	6.32E+00	3.16E-03
Propylene Oxide	2.90E-05	4.76E-03	4.17E+01	2.08E-02	9.51E-03	8.33E+01	4.17E-02
Toluene	1.30E-04	2.13E-02	1.87E+02	9.34E-02	4.26E-02	3.74E+02	1.87E-01
Xylenes	6.40E-05	1.05E-02	9.19E+01	4.60E-02	2.10E-02	1.84E+02	9.19E-02
TOTAL HAPs					**1.25E+00**	**1.10E+04**	**5.49E+00**

[a] Emission factors from AP-42, Section 3.1, "Stationary Gas Turbines," Table 3.1-3.

[b] Factor shown is in units of g/HP-hr, as recommended by the Louisiana Department of Environmental Quality.

Table B-3. HAP Emissions from Turbine (Standby)

Process Equipment:	Gas Turbine	(Standby Operation Only)
Unit Rating:	16,400	HP
Fuel Type:	Natural Gas	
Fuel Heat Content:	1,050	Btu/SCF
Fuel Usage Factor:	9.524	SCF/HP-hr
Heat Input:	164.00	MMBtu/hr
Hourly Fuel Usage:	156,194	SCF/hr
Annual Operating Hours:	192	hr/yr
Annual Fuel Usage:	29,989,171	SCF/yr

HAP Constituent	Emission Factor[a] lb/MMBtu	Air Emissions 1 Gas Turbine		
		lb/hr	lb/yr	tpy
1,3-Butadiene	4.30E-07	7.05E-05	1.35E-02	6.77E-06
Acetaldehyde	4.00E-05	6.56E-03	1.26E+00	6.30E-04
Acrolein	6.40E-06	1.05E-03	2.02E-01	1.01E-04
Benzene	1.20E-05	1.97E-03	3.78E-01	1.89E-04
Ethylbenzene	3.20E-05	5.25E-03	1.01E+00	5.04E-04
Formaldehyde[b]	1.59E-02	5.75E-01	1.10E+02	5.52E-02
Naphthalene	1.30E-06	2.13E-04	4.09E-02	2.05E-05
PAH	2.20E-06	3.61E-04	6.93E-02	3.46E-05
Propylene Oxide	2.90E-05	4.76E-03	9.13E-01	4.57E-04
Toluene	1.30E-04	2.13E-02	4.09E+00	2.05E-03
Xylenes	6.40E-05	1.05E-02	2.02E+00	1.01E-03
TOTAL HAPs		**6.27E-01**	**1.20E+02**	**6.02E-02**

[a] Emission factors from AP-42, Section 3.1, "Stationary Gas Turbines," Table 3.1-3.

[b] Factor shown is in units of g/HP-hr, as recommended by the Louisiana Department of Environmental Quality.

Table B-4. HAP Emissions from Firewater Drivers

Process Equipment:	Firewater Driver	
Unit Rating:	1,100	HP
Fuel Type:	Diesel	
Fuel Heat Content:	145,000	Btu/gal
Fuel Usage Factor:	0.0483	gal/HP-hr
Heat Input:	7.70	MMBtu/hr
Hourly Fuel Usage:	53.13	gal/hr
Annual Operating Hours:	52	hr/yr
Annual Fuel Usage:	2763	gal/yr

HAP Constituent	Emission Factor[a] lb/MMBtu	Air Emissions					
		1 Firewater Driver			2 Firewater Drivers		
		lb/hr	lb/yr	tpy	lb/hr	lb/yr	tpy
Benzene	7.76E-04	5.98E-03	3.11E-01	1.55E-04	1.20E-02	6.22E-01	3.11E-04
Toluene	2.81E-04	2.16E-03	1.13E-01	5.63E-05	4.33E-03	2.25E-01	1.13E-04
Xylenes	1.93E-04	1.49E-03	7.73E-02	3.87E-05	2.97E-03	1.55E-01	7.73E-05
Propylene	2.79E-03	2.15E-02	1.12E+00	5.59E-04	4.30E-02	2.24E+00	1.12E-03
Formaldehyde	7.89E-05	6.08E-04	3.16E-02	1.58E-05	1.22E-03	6.32E-02	3.16E-05
Acetaldehyde	2.52E-05	1.94E-04	1.01E-02	5.05E-06	3.88E-04	2.02E-02	1.01E-05
Acrolein	7.88E-06	6.07E-05	3.16E-03	1.58E-06	1.21E-04	6.31E-03	3.16E-06
Naphthalene	1.30E-04	1.00E-03	5.21E-02	2.60E-05	2.00E-03	1.04E-01	5.21E-05
Acenaphthylene	9.23E-06	7.11E-05	3.70E-03	1.85E-06	1.42E-04	7.40E-03	3.70E-06
Acenaphthene	4.68E-06	3.61E-05	1.87E-03	9.37E-07	7.21E-05	3.75E-03	1.87E-06
Fluorene	1.28E-05	9.86E-05	5.13E-03	2.56E-06	1.97E-04	1.03E-02	5.13E-06
Phenanthrene	4.08E-05	3.14E-04	1.63E-02	8.17E-06	6.29E-04	3.27E-02	1.63E-05
Anthracene	1.23E-06	9.48E-06	4.93E-04	2.46E-07	1.90E-05	9.85E-04	4.93E-07
Fluoranthene	4.03E-06	3.10E-05	1.61E-03	8.07E-07	6.21E-05	3.23E-03	1.61E-06
Pyrene	3.71E-06	2.86E-05	1.49E-03	7.43E-07	5.72E-05	2.97E-03	1.49E-06
Benz(a)anthracene	6.22E-07	4.79E-06	2.49E-04	1.25E-07	9.58E-06	4.98E-04	2.49E-07
Chrysene	1.53E-06	1.18E-05	6.13E-04	3.06E-07	2.36E-05	1.23E-03	6.13E-07
Benzo(b)fluoranthene	1.11E-06	8.55E-06	4.45E-04	2.22E-07	1.71E-05	8.89E-04	4.45E-07
Benzo(k)fluoranthene	2.18E-07	1.68E-06	8.73E-05	4.37E-08	3.36E-06	1.75E-04	8.73E-08
Benzo(a)pyrene	2.57E-07	1.98E-06	1.03E-04	5.15E-08	3.96E-06	2.06E-04	1.03E-07
Indeno(1,2,3-cd)pyrene	4.14E-07	3.19E-06	1.66E-04	8.29E-08	6.38E-06	3.32E-04	1.66E-07
Dibenz(a,h)anthracene	3.46E-07	2.67E-06	1.39E-04	6.93E-08	5.33E-06	2.77E-04	1.39E-07
Benzo(g,h,l)perylene	5.56E-07	4.28E-06	2.23E-04	1.11E-07	8.57E-06	4.45E-04	2.23E-07
TOTAL HAPs					**6.72E-02**	**3.50E+00**	**1.75E-03**

[a] Emission factors from AP-42, Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines," Tables 3.4-3 and 3.4-4.

Table B- 5. HAP Emissions from Emergency Generators

Process Equipment:	Emergency Generator	
Unit Rating:	1,100	HP
Fuel Type:	Diesel	
Fuel Heat Content:	145,000	Btu/gal
Fuel Usage Factor:	0.0483	gal/HP-hr
Heat Input:	7.70	MMBtu/hr
Hourly Fuel Usage:	53.13	gal/hr
Annual Operating Hours:	192	hr/yr
Annual Fuel Usage:	10,201	gal/yr

HAP Constituent	Emission Factor[a] lb/MMBtu	Air Emissions					
		1 Emergency Generator			2 Emergency Generators		
		lb/hr	lb/yr	tpy	lb/hr	lb/yr	tpy
Benzene	7.76E-04	5.98E-03	1.15E+00	5.74E-04	1.20E-02	2.30E+00	1.15E-03
Toluene	2.81E-04	2.16E-03	4.16E-01	2.08E-04	4.33E-03	8.31E-01	4.16E-04
Xylenes	1.93E-04	1.49E-03	2.85E-01	1.43E-04	2.97E-03	5.71E-01	2.85E-04
Propylene	2.79E-03	2.15E-02	4.13E+00	2.06E-03	4.30E-02	8.25E+00	4.13E-03
Formaldehyde	7.89E-05	6.08E-04	1.17E-01	5.84E-05	1.22E-03	2.33E-01	1.17E-04
Acetaldehyde	2.52E-05	1.94E-04	3.73E-02	1.86E-05	3.88E-04	7.45E-02	3.73E-05
Acrolein	7.88E-06	6.07E-05	1.17E-02	5.83E-06	1.21E-04	2.33E-02	1.17E-05
Naphthalene	1.30E-04	1.00E-03	1.92E-01	9.61E-05	2.00E-03	3.85E-01	1.92E-04
Acenaphthylene	9.23E-06	7.11E-05	1.37E-02	6.83E-06	1.42E-04	2.73E-02	1.37E-05
Acenaphthene	4.68E-06	3.61E-05	6.92E-03	3.46E-06	7.21E-05	1.38E-02	6.92E-06
Fluorene	1.28E-05	9.86E-05	1.89E-02	9.47E-06	1.97E-04	3.79E-02	1.89E-05
Phenanthrene	4.08E-05	3.14E-04	6.03E-02	3.02E-05	6.29E-04	1.21E-01	6.03E-05
Anthracene	1.23E-06	9.48E-06	1.82E-03	9.10E-07	1.90E-05	3.64E-03	1.82E-06
Fluoranthene	4.03E-06	3.10E-05	5.96E-03	2.98E-06	6.21E-05	1.19E-02	5.96E-06
Pyrene	3.71E-06	2.86E-05	5.49E-03	2.74E-06	5.72E-05	1.10E-02	5.49E-06
Benz(a)anthracene	6.22E-07	4.79E-06	9.20E-04	4.60E-07	9.58E-06	1.84E-03	9.20E-07
Chrysene	1.53E-06	1.18E-05	2.26E-03	1.13E-06	2.36E-05	4.53E-03	2.26E-06
Benzo(b)fluoranthene	1.11E-06	8.55E-06	1.64E-03	8.21E-07	1.71E-05	3.28E-03	1.64E-06
Benzo(k)fluoranthene	2.18E-07	1.68E-06	3.22E-04	1.61E-07	3.36E-06	6.45E-04	3.22E-07
Benzo(a)pyrene	2.57E-07	1.98E-06	3.80E-04	1.90E-07	3.96E-06	7.60E-04	3.80E-07
Indeno(1,2,3-cd)pyrene	4.14E-07	3.19E-06	6.12E-04	3.06E-07	6.38E-06	1.22E-03	6.12E-07
Dibenz(a,h)anthracene	3.46E-07	2.67E-06	5.12E-04	2.56E-07	5.33E-06	1.02E-03	5.12E-07
Benzo(g,h,l)perylene	5.56E-07	4.28E-06	8.22E-04	4.11E-07	8.57E-06	1.64E-03	8.22E-07
TOTAL HAPs					**6.72E-02**	**1.29E+01**	**6.45E-03**

[a] Emission factors from AP-42, Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines," Tables 3.4-3 and 3.4-4.

Table B-6. HAP Emisssions from Cranes

Process Equipment:	Crane	
Unit Rating:	338	HP
Fuel Type:	Diesel	
Fuel Heat Content:	145,000	Btu/gal
Fuel Usage Factor:	0.0483	gal/HP-hr
Heat Input:	2.37	MMBtu/hr
Hourly Fuel Usage:	16.33	gal/hr
Annual Operating Hours:	52	hr/yr
Annual Fuel Usage:	849	gal/yr

HAP Constituent	Emission Factor[a] lb/MMBtu	Air Emissions					
		1 Crane			3 Cranes		
		lb/hr	lb/yr	tpy	lb/hr	lb/yr	tpy
Benzene	9.33E-04	2.21E-03	1.15E-01	5.74E-05	6.63E-03	3.45E-01	1.72E-04
Toluene	4.09E-04	9.68E-04	5.03E-02	2.52E-05	2.90E-03	1.51E-01	7.55E-05
Xylenes	2.85E-04	6.75E-04	3.51E-02	1.75E-05	2.02E-03	1.05E-01	5.26E-05
Propylene	2.58E-03	6.11E-03	3.18E-01	1.59E-04	1.83E-02	9.53E-01	4.76E-04
1,3-Butadiene	3.91E-05	9.26E-05	4.81E-03	2.41E-06	2.78E-04	1.44E-02	7.22E-06
Formaldehyde	1.18E-03	2.79E-03	1.45E-01	7.26E-05	8.38E-03	4.36E-01	2.18E-04
Acetaldehyde	7.67E-04	1.82E-03	9.44E-02	4.72E-05	5.45E-03	2.83E-01	1.42E-04
Acrolein	9.25E-05	2.19E-04	1.14E-02	5.69E-06	6.57E-04	3.42E-02	1.71E-05
Naphthalene	8.48E-05	2.01E-04	1.04E-02	5.22E-06	6.02E-04	3.13E-02	1.57E-05
Acenaphthylene	5.06E-06	1.20E-05	6.23E-04	3.11E-07	3.59E-05	1.87E-03	9.34E-07
Acenaphthene	1.42E-06	3.36E-06	1.75E-04	8.74E-08	1.01E-05	5.24E-04	2.62E-07
Fluorene	2.92E-05	6.91E-05	3.59E-03	1.80E-06	2.07E-04	1.08E-02	5.39E-06
Phenanthrene	2.94E-05	6.96E-05	3.62E-03	1.81E-06	2.09E-04	1.09E-02	5.43E-06
Anthracene	1.87E-06	4.43E-06	2.30E-04	1.15E-07	1.33E-05	6.91E-04	3.45E-07
Fluoranthene	7.61E-06	1.80E-05	9.37E-04	4.68E-07	5.40E-05	2.81E-03	1.41E-06
Pyrene	4.78E-06	1.13E-05	5.88E-04	2.94E-07	3.39E-05	1.77E-03	8.83E-07
Benzo(a)anthracene	1.68E-06	3.98E-06	2.07E-04	1.03E-07	1.19E-05	6.20E-04	3.10E-07
Chrysene	3.53E-07	8.36E-07	4.35E-05	2.17E-08	2.51E-06	1.30E-04	6.52E-08
Benzo(b)fluoranthene	9.91E-08	2.35E-07	1.22E-05	6.10E-09	7.04E-07	3.66E-05	1.83E-08
Benzo(k)fluoranthene	1.55E-07	3.67E-07	1.91E-05	9.54E-09	1.10E-06	5.72E-05	2.86E-08
Benzo(a)pyrene	1.88E-07	4.45E-07	2.31E-05	1.16E-08	1.34E-06	6.94E-05	3.47E-08
Indeno(1,2,3-cd)pyrene	3.75E-07	8.88E-07	4.62E-05	2.31E-08	2.66E-06	1.38E-04	6.92E-08
Dibenz(a,h)anthracene	5.83E-07	1.38E-06	7.18E-05	3.59E-08	4.14E-06	2.15E-04	1.08E-07
Benzo(g,h,l)perylene	4.89E-07	1.16E-06	6.02E-05	3.01E-08	3.47E-06	1.81E-04	9.03E-08
TOTAL HAPs					**4.58E-02**	**2.38E+00**	**1.19E-03**

[a] Emission factors from AP-42, Section 3.3, "Gasoline And Diesel Industrial Engines," Table 3.3-2.

Table B-7. HAP Emissions from Sales Gas Heater

Process Equipment:	Sales Gas Heater	
Fuel Type:	Natural Gas	
Fuel Heat Content:	1,050	Btu/SCF
Heat Input:	20.00	MMBtu/hr
Hourly Fuel Usage:	19,048	SCF/hr
Annual Operating Hours:	8760	hr/yr
Annual Fuel Usage:	166,857,143	SCF/yr

HAP Constituent	Emission Factor[a] $lb/10^6$ scf	Air Emissions 1 Sales Gas Heater		
		lb/hr	lb/yr	tpy
2-Methylnaphthalene	2.40E-05	4.57E-07	4.00E-03	2.00E-06
3-Methylchloranthrene	1.80E-06	3.43E-08	3.00E-04	1.50E-07
7,12-Dimethylbenz(a)anthracene	1.60E-05	3.05E-07	2.67E-03	1.33E-06
Acenaphthene	1.80E-06	3.43E-08	3.00E-04	1.50E-07
Acenaphthylene	1.80E-06	3.43E-08	3.00E-04	1.50E-07
Anthracene	2.40E-06	4.57E-08	4.00E-04	2.00E-07
Benz(a)anthracene	1.80E-06	3.43E-08	3.00E-04	1.50E-07
Benzene	2.10E-03	4.00E-05	3.50E-01	1.75E-04
Benzo(a)pyrene	1.20E-06	2.29E-08	2.00E-04	1.00E-07
Benzo(b)fluoranthene	1.80E-06	3.43E-08	3.00E-04	1.50E-07
Benzo(g,h,i)perylene	1.20E-06	2.29E-08	2.00E-04	1.00E-07
Benzo(k)fluoranthene	1.80E-06	3.43E-08	3.00E-04	1.50E-07
Butane	2.10E+00	4.00E-02	3.50E+02	1.75E-01
Chrysene	1.80E-06	3.43E-08	3.00E-04	1.50E-07
Dibenzo(a,h)anthracene	1.20E-06	2.29E-08	2.00E-04	1.00E-07
Dichlorobenzene	1.20E-03	2.29E-05	2.00E-01	1.00E-04
Ethane	3.10E+00	5.90E-02	5.17E+02	2.59E-01
Fluoranthene	3.00E-06	5.71E-08	5.01E-04	2.50E-07
Fluorene	2.80E-06	5.33E-08	4.67E-04	2.34E-07
Formaldehyde	7.50E-02	1.43E-03	1.25E+01	6.26E-03
Hexane	1.80E+00	3.43E-02	3.00E+02	1.50E-01
Indeno(1,2,3-cd)pyrene	1.80E-06	3.43E-08	3.00E-04	1.50E-07
Naphthalene	6.10E-04	1.16E-05	1.02E-01	5.09E-05
Pentane	2.60E+00	4.95E-02	4.34E+02	2.17E-01
Phenanathrene	1.70E-05	3.24E-07	2.84E-03	1.42E-06
Propane	1.60E+00	3.05E-02	2.67E+02	1.33E-01
Pyrene	5.00E-06	9.52E-08	8.34E-04	4.17E-07
Toluene	3.40E-03	6.48E-05	5.67E-01	2.84E-04
TOTAL HAPs		**2.15E-01**	**1.88E+03**	**9.41E-01**

[a] Emission factors from AP-42, Section 1.4, "Natural Gas Combustion," Table 1.4-3.

HAP EMISSION FACTOR REFERENCE DOCUMENTS

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene[e]	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde[f]	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide[d]	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

[a] SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

[e] Benzene with SCONOX catalyst is 9.1 E-07, rating of D.

[f] Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene[b]	9.33 E-04
Toluene[b]	4.09 E-04
Xylenes[b]	2.85 E-04
Propylene[b]	2.58 E-03
1,3-Butadiene[b,c]	<3.91 E-05
Formaldehyde[b]	1.18 E-03
Acetaldehyde[b]	7.67 E-04
Acrolein[b]	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene[b]	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,l)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

[a] Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.
[b] Hazardous air pollutant listed in the *Clean Air Act*.
[c] Based on data from 1 engine.

Table 3.4-3. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR LARGE UNCONTROLLED STATIONARY DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (lb/MMBtu) (fuel input)
Benzene[b]	7.76 E-04
Toluene[b]	2.81 E-04
Xylenes[b]	1.93 E-04
Propylene	2.79 E-03
Formaldehyde[b]	7.89 E-05
Acetaldehyde[b]	2.52 E-05
Acrolein[b]	7.88 E-06

[a]Based on 1 uncontrolled diesel engine from Reference 7. Source Classification Code 2-02-004-01. Not enough information to calculate the output-specific emission factors of lb/hp-hr. To convert from lb/MMBtu to ng/J, multiply by 430.
[b]Hazardous air pollutant listed in the *Clean Air Act*.

Table 3.4-4. PAH EMISSION FACTORS FOR LARGE UNCONTROLLED STATIONARY DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

PAH	Emission Factor (lb/MMBtu) (fuel input)
Naphthalene[b]	1.30 E-04
Acenaphthylene	9.23 E-06
Acenaphthene	4.68 E-06
Fluorene	1.28 E-05
Phenanthrene	4.08 E-05
Anthracene	1.23 E-06
Fluoranthene	4.03 E-06
Pyrene	3.71 E-06
Benz(a)anthracene	6.22 E-07
Chrysene	1.53 E-06
Benzo(b)fluoranthene	1.11 E-06
Benzo(k)fluoranthene	<2.18 E-07
Benzo(a)pyrene	<2.57 E-07
Indeno(1,2,3-cd)pyrene	<4.14 E-07
Dibenz(a,h)anthracene	<3.46 E-07
Benzo(g,h,l)perylene	<5.56 E-07
TOTAL PAH	<2.12 E-04

[a] Based on 1 uncontrolled diesel engine from Reference 7. Source Classification Code 2-02-004-01. Not enough information to calculate the output-specific emission factors of lb/hp-hr. To convert from lb/MMBtu to ng/J, multiply by 430.

[b] Hazardous air pollutant listed in the *Clean Air Act*.

Formaldehyde Emissions

Formaldehyde Emissions From Internal Combustion Engines and Turbines

Applicability to Title V

(Revised November 18, 1996)
Formaldehyde emissions from combustion of fossil fuels are exempt from LAC33:III.Chapter 51, but are not exempt from Section 112(b) of the Clean Air Act. Facilities with small engines will not be required to speciate combustion VOC emissions, and only formaldehyde emissions will be required of large engines and gas turbines or facilities* approaching 10 TPY formaldehyde trigger value.

GRID-HAPCalc Version 1 gives the following formaldehyde emission factors for gas-fired engines:

DESCRIPTION	FACTOR (g/hp-hr)
Turbine (Pipeline or Field Gas)	0.0159
Pipeline Gas-Fired Engines	
4-cycle, rich burn IC	0.0623
2-cycle, lean burn IC	0.0879
4-cycle, lean burn IC	0.1011
Field Gas-Fired Engines	
4-cycle, rich burn IC	0.0381
4-cycle, lean burn IC	0.1683
2-cycle, lean burn IC	0.2432

Examples Approaching Trigger for Formaldehyde:

- All Turbines: 60,000(0.0159/453.6)(4.38)=9.21 TPY
- Pipeline Gas, worst case ICs: 10,000(0.1011/453.6)(4.38)=9.76 TPY
- Field Gas, worst case ICs: 4,000(0.2432/453.6)(4.38)=9.39 TPY

Formaldehyde emissions are required for the following equipment or

facilities* :

1. Over 4,000 hp for engines using field gas fuel
2. Over 10,000 hp for engines using pipeline gas fuel
3. Over 60,000 hp for turbines using either gas fuel
4. Any combination of the above yielding over 9 TPY formaldehyde

**Formaldehyde emissions cannot be aggregated for oil and gas facilities, compressor or pump stations, and similar units. (Approved by EPA and LAC 33:III.5105.B.5.)*

Send e- mail to webmasterdeq@LA.GOV or any member of our WWW Task Force
with questions or comments about this web site. To contact us by phone or mail,
see our Office Address/Phone listing.

APPENDIX C – VENDOR SPECIFICATIONS

Estimated Power Island Emissions

Ecology and Environment, Inc.

Quoted using data available as of September 15, 2003

(1) Gas Fuel TITAN 130-19501S Axial		**Per Unit**	**Plant Total**
Ambient Temperature	°F	30 °F	
Fuel Type		Gas	
Assumed Fuel Sulphur Content	lb/MMBTU (HHV)	0.00	
Gas Turbine Exhaust Flow	lb/hr	409,134	409,134
Duct Burner Fuel Flow	lb/hr	0	0
Stack Exhaust Flow	lb/hr	409,134	409,134
FG Temperature Leaving Gas Turbine	°F	892	
FG Temperature Leaving Duct Burner	°F	892	
FG Temperature At Stack	°F	892	
Heat Input to Gas Turbine	MMBtu/hr (LHV)	146.4	146.4
Heat Input from Duct Firing	MMBtu/hr (LHV)	0.0	0.0
Additive NOx from Duct Firing	lb/MMBTU (HHV)	0.080	
Additive CO from Duct Firing	lb/MMBTU (HHV)	0.080	
Additive UHC as CH4 from Duct Firing	lb/MMBTU (HHV)	0.045	
PM-10 Particulates from Gas Turbine	lb/MMBTU (HHV)	0.042	
Additive PM-10 Particulates from Duct Firing	lb/MMBTU (HHV)	0.010	
Turbine Exhaust Gas Analysis			
H_2O	% vol	5.9%	
N_2	% vol	75.8%	
CO_2	% vol	3.0%	
O_2	% vol	14.5%	
SO_2	% vol	0.0%	
Argon	% vol	0.9%	
Flue Gas Analysis After Duct Burner			
H_2O	% vol	5.9%	
N_2	% vol	75.7%	
CO_2	% vol	3.0%	
O_2	% vol	14.4%	
SO_2	% vol	0.0%	
Argon	% vol	0.9%	
Gas Turbine Exhaust Emissions			
NOx	ppmvd @ 15% O2	25	25
	lb/hr	14.5	14.5
CO	ppmvd @ 15% O2	50	50
	lb/hr	17.6	17.6
UHC	ppmvd @ 15% O2	25	25
	lb/hr	5.0	5.0
PM_{10}	lb/hr	6.8	6.8
SO_2	lb/hr	0.6	0.6

(1) Gas Fuel TITAN 130-19501S Axial		**Per Unit**	**Plant Total**
Total Emissions After Duct Burner			
NOx	ppmvd @ 15% O2	25	25
	lb/hr	14.5	14.5
CO	ppmvd @ 15% O2	50	50
	lb/hr	17.6	17.6
UHC	ppmvd @ 15% O2	25	25
	lb/hr	5.0	5.0
PM_{10}	lb/hr	6.8	6.8
SO_2	lb/hr	0.6	0.6
Exhaust Emissions At Stack			
NOx	ppmvd @ 15% O2	25	25
	lb/MMBtu, HHV	0.109	
	lb/hr	14.5	14.5
	tons/year	63.5	63.5
CO	ppmvd @ 15% O2	50	50
	lb/MMBtu, HHV	0.133	
	lb/hr	17.6	17.6
	tons/year	77.3	77.3
UHC	ppmvd @ 15% O2	25	25
	lb/MMBtu, HHV	0.038	
	lb/hr	5.0	5.0
	tons/year	22.1	22.1
VOC	ppmvd @ 15% O2	2	2
	lb/MMBtu, HHV	0.009	
	lb/hr	0.5	0.5
	tons/year	2.2	2.2
PM_{10}	lb/hr	6.8	6.8
	lb/MMBtu, HHV	0.046	
	tons/year	29.7	29.7
SO_2	lb/hr	0.6	0.6
	lb/MMBtu, HHV	0.000	
	tons/year	2.4	2.4
SCR Ammonia Slip	ppmvd @ 15% O2	N/A	
SCR Reduction Efficiency	%	N/A	
CO Catalyst Reduction Efficiency	%	N/A	
UHC Catalyst Reduction Efficiency	%	N/A	

General Notes

SO2 emissions depend upon the fuel's sulfur content. The current estimate is based upon the assumption of 100% conversion of fuel sulphur to SO2. SO2 and PM10 emissions at site conditions have been calculated on EPA recommended method. Zero fuel bound nitrogen is assumed for gaseous fuels, less than 0.02% for liquid fuels. Emissions are subject to actual fuel characteristics and a Solar Turbines Engineering review will be required to verify the estimates given above.

Turbine Emissions Notes:

The table below gives the load ranges to which the turbine emissions listed above apply.

Pollutant	Load Range
NOx	50 to 100%
CO	50 to 100%
UHC	50 to 100%

Fuels must comply with Solar specification ES 9-98.

Values applicable for ambient temperatures greater than 0°F (-20°C).

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Emission Estimates at Start-up, Shutdown, and Commissioning for SoLoNOx Products

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PURPOSE

Emissions during start-up, shutdown, and commissioning of Solar's size class of gas turbine are negligible and are not warranted by Solar. Without appropriate forewarning, however, many customers and regulators will treat Solar's turbines as though they were large utility turbines. The purpose of this PIL is to provide insight into the different situation with Solar's class of turbine and provide emission estimates for start-up, shutdown, and commissioning.

INTRODUCTION

Due to the surge of energy projects in the utility sector and the start-up and shutdown emission characteristics of large utility turbines, some regulatory agencies have been asking Solar's customers to account for emissions during start-up and shutdown conditions in their air permitting. The operating characteristics and emissions profile of Solar's size class of turbine is different than those of a utility-size combined-cycle power plant. This basic fact is often overlooked by regulatory agencies and can cause Solar's customers to expend significant effort in estimating start-up and shutdown emissions that are essentially insignificant. In most cases, once our estimated start-up emissions are relayed to the permitting engineers, the issue is dropped.

Start-up occurs in one of three modes: cold, warm, or hot. In general, the start-up duration for a hot, warm, or cold *Solar* turbine is less than 10 minutes in simple-cycle and most combined heat and power designs. Heat recovery steam generator (HRSG) steam pressure is usually 250 psig or less. At 250 psig or less, thermal stress within the HRSG is minimized and, therefore, firing ramp up is not limited.

A utility-size combined-cycle power plant typically operates at 1800 to 2400 psig. At 1800 to 2400 psig, a 2 to 3 hour start-up sequence is required for a **cold** start (steam turbine shutdown for greater than 72 hours), 1 to 2 hours for a **warm** start (steam turbine shutdown for 8 to 72 hours); and 30 minutes for a **hot** start (steam turbine shutdown for less than 8 hours). Large simple-cycle gas turbines generally start-up in 10 to 30 minutes.

Start-up, shutdown, and commissioning emissions will **not** be guaranteed by Solar Turbines. The information presented in this document is representative for both single and two-shaft engines only. Operation of duct burners and/or any add-on control equipment is not considered in the estimates.

START-UP EMISSION ESTIMATES

The start-up duration is the same for cold, warm, and hot starts. Expected start-up emissions are summarized in Table 1, in parts per million by volume (ppmv, and in Table 2, in pounds per year for each product. The emission estimates are calculated from empirical exhaust characteristics. Getting to the *SoLoNOx* mode takes three steps:

1. Purge-crank
2. Ignition and acceleration to idle
3. Loading / thermal stabilization

During the "purge-crank" step, rotation of the turbine shaft is accomplished with an electric starter motor to remove any residual fuel gas in the engine flow path and exhaust. During "ignition and acceleration to idle," fuel is introduced into the combustor and ignited in a diffusion flame mode

Table 1. Estimated Emissions during Start-Up (ppmv)

Start-up Step	Combustion Mode	Approx. Time, minutes	NOx, ppmv	CO, ppmv	UHC, ppmv
1. Purge-Crank	None	4	---	---	---
2. Ignition-Idle-Generator Synchronization	Diffusion	3	50	3500	500
3. Loading / Thermal Stabilization	Transitional	6	70	2200	300
4. 50% to Full Load	*SoLoNOx*	Variable	<25	<50	<25

and the engine rotor is accelerated to idle speed. The third step consists of applying up to 50% load while allowing the combustion flame to transition and stabilize. Once 50% load is achieved, the turbine transitions to *SoLoNOx* mode (Step 4) and the engine control system begins to hold the combustion primary zone temperature and limit pilot fuel to achieve the carbon monoxide (CO) and nitrogen oxides (NOx) emission levels.

The specific load at which a unit enters *SoLoNOx* mode (Step 4) varies by engine model and ambient temperature. For two-shaft engine, the *SoLoNOx* "trigger" load also varies by gas producer speed (NGP).

It is important to note that Steps 2 and 3 are short-term transient conditions making up less than 10 minutes. No emission guarantee is provided by Solar for <50% load. NOx, CO, and unburned hydrocarbons (UHC) are guaranteed at 25 ppmv, 50 ppmv, and 25 ppmv respectively, when operating greater than 50% load.

SHUTDOWN EMISSIONS

Normal, planned cooldown / shutdown duration varies by engine model. The *Centaur* 40, *Centaur* 50, and *Taurus* 60 take about five minutes. The *Taurus* 70, *Mars* 90 and 100, and *Titan* 130 take about 10 minutes. Typically, the emissions will be similar to Start-up Step 4 for 90 seconds and Step 3 for the balance of the estimated duration (assumes unit was operating at full-load).

COMMISSIONING EMISSIONS

Commissioning generally takes place over a two-week period. Static testing, where no combustion occurs, usually requires one week and no emissions are expected. Dynamic testing, where combustion will occur, will see the engine start and shutdown a number of times and a variety of loads will be placed on the system. It is impossible to predict how long the turbine will run and in what combustion / emissions mode it will be running. The dynamic testing period is generally followed by one to two days of "tune-up" during which the turbine is running at various loads, most likely within low emissions mode (warranted emissions range).

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Table 2. Estimation of Start-up and Shutdown Emissions (lb/yr) for SoLoNOx Gas Fuel

Data will NOT be warranted under any circumstances

		Centaur 40 4700S						Centaur 50 6200SII						Taurus 60 7800SII						Taurus 70 10300S					
		Exhaust Flowrate (lb/hr)	O2 %	H2O%	NOx (lbs)	CO (lbs)	UHC (lbs)	Exhaust Flowrate (lb/hr)	O2 %	H2O%	NOx (lbs)	CO (lbs)	UHC (lbs)	Exhaust Flowrate (lb/hr)	O2 %	H2O%	NOx (lbs)	CO (lbs)	UHC (lbs)	Exhaust Flowrate (lb/hr)	O2 %	H2O%	NOx (lbs)	CO (lbs)	UHC (lbs)
Start-up	Step 2 (3 min)	146,415	19.13	2.44	0.13	5.33	0.43	150,409	18.52	2.99	0.18	7.63	0.62	171,774	19.3	2.29	0.13	5.56	0.45	211,378	18.56	2.95	0.25	10.53	0.86
	Step 3 (6 min)	146,415	19.13	2.44	0.35	6.70	0.52	150,409	18.52	2.99	0.50	9.59	0.75	171,744	19.3	2.29	0.37	6.99	0.54	211,378	18.56	2.95	0.69	13.24	1.03
Total Start-up Emissions					0.5	12.0	1.0				0.7	17.2	1.4				0.5	12.5	1.0				0.9	23.8	1.9
Shut-down	Step 4 (90 sec)	147,718	15.46	5.70	0.11	0.13	0.04	151,411	14.35	6.68	0.13	0.16	0.05	173,937	14.33	6.70	0.15	0.19	0.05	213,837	14.32	6.70	0.19	0.23	0.07
	Step 3 (3.5 min)	146,415	19.13	2.44	0.20	3.91	0.30	150,409	18.52	2.99	0.29	5.60	0.44	171,744	19.3	2.29	0.21	4.08	0.32	211,378	18.56	2.95	0.98	18.76	1.46
Total Shut-down Emissions					0.3	4.0	0.3				0.4	5.8	0.5				0.4	4.3	0.4				1.2	19.0	1.5

		Mars 90 13000S						Mars 100 15000S						Titan 130 19500S					
		Exhaust Flowrate (lb/hr)	O2 %	H2O%	NOx (lbs)	CO (lbs)	UHC (lbs)	Exhaust Flowrate (lb/hr)	O2 %	H2O%	NOx (lbs)	CO (lbs)	UHC (lbs)	Exhaust Flowrate (lb/hr)	O2 %	H2O%	NOx (lbs)	CO (lbs)	UHC (lbs)
Start-up	Step 2 (3 min)	179,125	17.2	4.15	0.35	14.71	1.20	179,761	17.18	4.17	0.35	14.84	1.21	390,263	18.88	2.66	0.39	16.52	1.35
	Step 3 (6 min)	179,125	17.2	4.15	0.97	18.49	1.44	179,761	17.18	4.17	0.98	18.65	1.45	390,263	18.88	2.66	1.09	20.76	1.62
Total Start-up Emissions (lbs)					1.3	33.2	2.6				1.3	33.5	2.7				1.5	37.3	3.0
Shut-down	Step 4 (90 sec)	318,755	15.0	6.11	0.25	0.31	0.09	331,545	14.62	6.44	0.29	0.36	0.10	394,751	14.39	6.64	0.35	0.42	0.12
	Step 3 (8.5 min)	179,125	17.2	4.15	1.37	26.20	2.04	179,761	17.18	4.17	1.38	26.43	2.06	390,263	18.88	2.66	1.54	29.42	2.29
Total Shut-down Emissions (lbs)					1.6	26.5	2.1				1.7	26.8	2.2				1.9	29.8	2.4

Assumes ISO conditions: 59F, 60% RH, sea level, no losses
Exhaust flowrates for Step 2 and 3 from FASTE @ 1% load using diffusion flame equivalent model; Mars 90 and 100 use 10% load diffusion flame data.
Exhaust flowrates for Step 4 from FASTE @ 100% load using SoLoNOx models.
Assumes unit is operating at full load prior to shut-down.
Assumes gas fuel.